Western's Responses to Customer Comments and Questions Regarding Information Provided at the May 14th Post-2004 Informal Rates Meeting

OUTLINE

INTRODUCTION

All of the rate information shared at the Informal Rates Meeting and provided in this document is subject to change during Western's formal rate process. Western is developing the proposed rates for the formal rate process, which may differ from the rate information shared at the Informal Rates Meeting. Western plans to initiate the formal rate process in early 2004.

In the informal rate process, Western has presented rate information that would be relevant if Western forms a Federal control area. Western's operational alternatives are being developed in a separate public process. The outcome of that public process will affect the rates developed through Western's formal rate process.

Questions about the rate information presented at the Informal Rates Meeting and Western's responses are shown below and grouped by topic, e.g. base resource, ancillary services, transmission, etc. Questions that relate to more than one topic or do not relate to a specific topic are grouped together under "General Questions". Questions were paraphrased and combined where possible without changing the meaning. At the end of the document are general comments that were also submitted to Western.

Below is an acronym list for acronyms used in this document.

AGC – Automatic Generation Control
ARR – Annual Revenue Requirement

BR – Base Resource

CAMS – Control Area Management Service
COI – California-Oregon Intertie
COTP – California-Oregon Transmission Project
CP – Coincident Peak
CPP – Custom Product Power
CVP – Central Valley Project

DOE – Department of Energy
DWR – State of California Department of Water Resources

E-Tag – Electronic Tag
ETC – Existing Transmission Contract

FERC – Federal Energy Regulatory Commission
FRN – Federal Register Notice
FLS – Full Load Service
FP – First Preference

GMC – Grid Management Charge
GWH – Gigawatthour

ISO – Independent System Operator

kW – Kilowatt
kWh - kilowatthour

MEFPC – Maximum Entitlement of First Preference Customers
MRR – Monthly Revenue Requirement
MW - Megawatt
MWH - Megawatthour

O&M – Operations and Maintenance
OATT – Open Access Transmission Tariff

PACI – Pacific Alternating Current Intertie
PG&E – Pacific Gas and Electric
PM – Portfolio Management
Post 04 – Post-2004

SC – Scheduling Coordinator
SSC&D – Scheduling, System Control and Dispatch
SCID – Scheduling Coordinator Identification

TAC – Transmission Access Charge
T&D – Transmission and Distribution
TS&D – Transmission Switching and Dispatch
TSS – Transmission Scheduling and Security

VR – Variable Resource

GENERAL QUESTIONS

1. Is it possible to prepare an estimated cost for a FLS/VR customer not in Western's control area that would include the following:

a. BR = _____/KWh.

BR will not be charged on a $/kWh basis. All BR customers regardless of what control area they are in, will pay their percentage share of the preference power MRR based on their BR percentage, adjusted for exchange energy. The estimated preference power MRR is independent of the amount of BR provided to the customers in any month. First preference customers will pay their percentage share of the preference power ARR based on their percentage of their load for the previous FY to the total CVP generation less project use loads for the previous fiscal year. The resulting percentage will be applied to the preference power ARR to determine their power cost.

b. CPP = ____/KWh.

The cost for CPP is unknown because the power purchases have not been made. CPP costs for VR customers will be passed through directly to each VR customer requesting Western to make the purchase. Additionally, the VR customer will be charged a Western administrative charge for making the purchase. Long-term CPP costs for FLS customers will be charged based on the amount of CPP used by the FLS customer. Any unused long-term CPP will sold to the market. Any revenues from selling the surplus CPP to the market will be allocated to each FLS customer based on the number of FLS customers in the group. Short-term (spot market) purchases to meet FLS customer loads will be charged to each specific customer for whom the purchase was made. The CPP cost for firming in the day-ahead market will be passed on to each customer contracting with Western to provide the service. The administrative fee for CPP purchases for FLS customers is included in the PM Service rate.

c. SC = _____/schedule.

The estimated cost per schedule for SC is dependent upon the total number of final daily schedules for all SC customers. The rate per schedule will fluctuate depending on the number of customers taking SC service and the total number of final daily schedules for all SC customers.

d. Third party charges:

1. Transmission = ____.

Under the assumptions used in Western's informal rate proposal, customers would continue to pay "embedded cost" for Federal power deliveries after 12/31/04. Currently, most CVP customers connected to ISO/PG&E transmission facilities are paying transmission rates based on the "embedded cost" for their Western firm power deliveries. "Embedded cost" is based on PG&E's sub-functionalized transmission rate methodology currently in place under Contract 2948A. For customers on other third party transmission systems, such as SMUD's, Western will pass through the third party transmission charge to each appropriate customer.

2. Exit fee = $27/MWH.

Western's understanding of PG&E's position on exit fees is: any new customer served by Western after 2004 is subject to exit fees; any existing customers whose delivery points were established between 1993 and 2004, and take supplemental power from PG&E may be charged exit fees for only for Western power that is not CVP generation, depending on whether or not they were a x/y customer at the time the DWR bond debt was incurred in 2001. **UPDATE**: Per the Response of PG&E to CVP Preference Power Post-2004 Implementation Group Motion for Clarification in CPUC Rulemaking 02-01-011 filed June 19, 2003, for existing Western customers, exit fees will apply to load that was served under a PG&E retail tariff on or after February 1, 2001.

3. ISO costs = _______.

An estimated average of ISO load based charges was obtained from the ISO. The estimated average for CY02 is $1.36/MWH. This estimated average does not include charges for FERC fees, transmission access or wheeling charges, ancillary services, balancing energy (i.e. deviations), or congestion. This estimated average includes charges for GMC bucket #1, Unaccounted for Energy, Emission Cost Recovery, Start Up Cost Recovery, Energy Neutrality, and Existing Contracts Neutrality.

h. Can this estimate be provided to my agency separately since this is for specific information?

At the informal rates meeting, Western provided data that customers could use to estimate their costs for products and services purchased from Western. This data is also available on Western's web site. Western does not have any better or additional data available at this time. If more information or better data becomes available in the near future, Western will include such data in the formal rate process.

2. Will end-use customers currently receiving transmission service under Contract 2948A be required to take or pay for any third-party transmission services after 1/1/05?

The cost and conditions of third party transmission service starting 1/1/05 will depend on whether the customer or Western takes the transmission service, and the terms and conditions agreed to by the parties.

3. Please describe all transmission services and charges provided to BR customers connected to PG&E's transmission grid.

The table below shows the customer categories and the services offered by Western. For each service, there are two rows. The top row for each service indicates whether or not the service must be taken by that customer category, is optional for that customer category, or is not available to that customer category. An X means that customer category must take the indicated service. Optional indicates that customer category may choose to take the service. If the row is blank, that service is not available to that customer category. The second row for each service shows the cost for the service. In addition to the services in the table, transmission service over ISO/PG&E's system will be required. Under Western's informal rates, customers would pay Western's estimated of "embedded costs" for ISO/PGE transmission service.

SERVICES/ Cost	**FLS Customer**	**BR & VR Customer**	**Project Use Loads**	**FP Customer**	**Transmission customer**	**Federal Control Area Customer**
CVP energy before BR			X	X		

			Cost sub-allocation	FP % of preference power ARR		
BR includes exchange programs	X	X				
	BR % of BR ARR	BR % of BR ARR				
Custom Product Power (CPP)	X	Optional		Optional for Load greater than MEFPC		
	Pass Thru Costs	Pass Thru Costs		Pass Thru Costs		
Scheduling Coordinator Service (SC)	Optional	Optional	X	Optional		
	$7.00 per Schedule plus a pass-through of ISO costs	$7.00 per Schedule plus a pass-through of ISO costs	Cost sub-allocation	$7.00/Schedule plus a pass-through of ISO costs		
Portfolio Management Service (PM)	X		In conjunction with Reclamation	X		
	$14.00/schedule		Cost sub-allocation	$14.00/schedule		
Scheduling, System Control and Dispatch Service (SSC&D)	X	X	X	X	X	
	Included in BR RR	Included in BR RR	Cost sub-allocation	Included in Preference Power ARR up to MEFPC	Component of transmission rate	
Reactive Supply & Voltage Control	X	X	X	X	X	

	Included in BR RR	Included in BR RR	Cost sub-allocation	Included in Power ARR up to MEFPC	Component of transmission rate	
Regulation & Frequency Response	See Note A	See Note A	See Note A	See Note A	See Note A	See Note A
	See Note A	See Note A	See Note A	See Note A	See Note A	$0.40/kW-Month
Energy Imbalance Service	See Note B	See Note B	See Note B	See Note B	See Note B	See Note B
	See Note B	See Note B	See Note B	See Note B	See Note B	See Note B
Operating Reserve – Spinning Reserve Service	X	X	X	X	Optional	Optional
	Included in BR ARR for BR deliveries only	Included in BR ARR for BR deliveries only	Cost sub-allocation	Included in preference Power RR up to MEFPC	See Note C	See Note C
Operating Reserve – Supplemental Reserve Service (Non-Spin)	X	X	X	X	Optional	Optional
	Included in BR ARR for BR deliveries only	Included in BR ARR for BR deliveries only	Cost sub-allocation	Included in preference Power RR up to MEFPC	See Note D	See Note D
COTP Transmission (Point-to-Point) Service					X	
					See Note E	
CVP Transmission Service					X	

(Network)					See Note F	
CVP Transmission Service (Point to Point)					X	
					See Note G	
PACI Transmission (Point-to-Point) Service					X	
					See Note H	
Control Area Management Service (CAMS)						X
						See Note I

Note A. Customers may receive regulation in one of two ways – through self provision (regulating for their own load) or by having the control area operator, by default, provide this service. For those loads in the ISO control area, charges for regulation will be determined under the ISO tariff. For Western's OATT customers and Federal control area customers, excluding project use loads, if regulation is provided from Western resources, the estimated charge is $0.40/kW-Month. Project use loads will pay the cost from the cost sub-allocation.

Note B. For customers in the ISO control area, charges for energy imbalance (deviations) will be determined under the ISO tariff. For Western's OATT customers and Federal control area customers, excluding project use loads, if energy imbalance is provided by Western, a +/- 1.5% bandwidth would apply. Deviations within the bandwidth require a return energy schedule. Deviations outside the bandwidth: under deliveries will be charged @ 150% of market prices and over deliveries will be deemed lost to the system. Project use loads will pay the cost from the cost sub-allocation.

Note C. For Western's OATT customers or Federal control area customers, excluding project use loads, that purchase spinning reserve from Western, the rate is $0.31/kW-Month or market price, whichever is greater. Project use loads will pay the cost from the cost sub-allocation.

Note D. For Western's OATT customers or Federal control area customers, excluding project use loads, that purchase supplemental (non-spin) reserve from Western, the rate is $0.19/kW-Month or market price, whichever is greater. Project use loads will pay the cost from the cost sub-allocation.

Note E. COTP point-to-point transmission formula rate consists of three components: transmission facilities ($1.30/kW-Month), SSC&D service (varies based on validated e-tags), and reactive supply and voltage control service ($0.07/kW-Month).

Note F. CVP network transmission formula rate consists of three components: transmission facilities (cost varies based on 12 coincident peaks of CVP transmission system), SSC&D service (varies based on validated e-tags), and reactive supply and voltage control service ($0.07/kW-Month). CVP Network Transmission Service costs will be included in the BR ARR for FLS and VR customers. CVP Network Transmission Service costs will be included in the FP percentage share of the preference power ARR. Project use loads will pay the cost from the cost sub-allocation.

Note G. CVP point-to-point transmission formula rate consists of three components: transmission facilities ($0.95/kW-Month), SSC&D service (varies based on validated e-tags), and reactive supply and voltage control service ($0.07/kW-Month).

Note H. PACI point-to-point transmission formula rate consists of three components: transmission facilities (includes ISO/PG&E T&D facility related costs for deliveries of Western power less Western's estimate of embedded costs), SSC&D service (varies based on validated e-tags), and reactive supply and voltage control service ($0.07/kW-Month).

Note I. This rate applies to entities that sign an Intra Control Area Agreement with Western. Project Use loads within the control area pay the costs from the cost sub-allocation.

a. What services would be required to deliver BR power to Tracy?

To deliver BR to Tracy requires CVP Network Transmission service, SSC&D service, reactive power and voltage control, and operating reserves.

b. What charges would apply to the delivery of BR power to Tracy and how would these charges be calculated? E.g., would the customer pay Western's proposed CVP transmission rate of $0.95/kW-mo, or would it pay Western's estimate of embedded costs, or both? How would the monthly billing determinant be calculated?

The cost for CVP network transmission service included in the BR ARR is around $10 million. Monthly billing determinant for CVP network transmission service for BR delivery is the customer's monthly BR percentage.

c. Will BR customers pay any ISO charges for delivery of BR power to Tracy? If so, what charges would apply and how would they be calculated?

Western does not anticipate any ISO charges for BR deliveries to Tracy within the Federal Control Area.

d. Will customers pay any Western charges for delivery of BR power to their meters over the PG&E system?

Customers would pay Western's estimate of embedded costs for transmission service over the ISO/PG&E transmission system.

4. Please describe how BR power would be scheduled to a customer located on the PG&E transmission system that obtained all of its supply from Western.

a. How many daily schedules would be needed to schedule the power to Tracy and from Tracy to the customer's meter?

The number of schedules required will vary depending on a customer's situation, e.g. use of CPP, etc.

b. What ISO charges would apply to the transaction?

Western anticipates that the customer would have to pay all ISO charges applicable under the ISO tariff at that time. ISO TAC charges above Western's estimate of embedded costs would be included in the PACI transmission ARR.

c. Would Western continue to read the customer's meter and provide metering data to PG&E?

If Western requires meter data to provide service to the customer, Western will read or make arrangements to have the meter read. If metering data is required by PG&E for transmission service and Western has the meter data, Western will provide the meter data to PG&E. For a FLS customer Western would continue to read the customer's meter and provide the metering data to the ISO/PG&E depending on transmission arrangements. For VR customers, the SC for the load would have the responsibility for reporting the customer meter data.

d. Who would charge for imbalance energy?

The applicable control area operator charges for imbalance energy.

e. Would PG&E play any role in scheduling, metering, imbalance energy, etc?

This question is outside of the scope of Western's informal rate process.

5. How does Western define a schedule for the SC Service rate, or for the CAMS rate? As noted earlier, we define a schedule as the details of a transaction, namely, the start and stop times, quantity and path.

Western defines a schedule for the SC service rate as a schedule required for that customer's load. Resource schedules for load are prepared by individual resource (i.e., imports, SC to SC trades). Western does not intend to use the number of schedules as a billing determinant for the CAMS rate. Western's current methodology uses control area load as the billing determinant.

6. Can Western provide a matrix of estimated rates (by delivery voltage) that would illustrate the "pass thru" costs associated with delivering federal power to preference customers served off the ISO grid? (Please include ISO transmission and PG&E distribution costs as applicable).

Western is unable to provide this information as part of its informal rate process. Customers could approach PG&E for this information.

7. It is important that Western first offer any excess non-spin reserves from the CVP to the preference power customers at CVP rates, as preference power customers have first rights to the CVP power products.

Western will market CVP related products and services according to the Post 2004 Power Marketing Plan. Rates for these products and services will be determined through Western's formal rate processes.

8. Does pass-through of charges mean that the BR Customer receiving the delivery pays all the associated Third Party Transmission cost?   What is meant by the phrase "...other than Western's, PG&E's or the ISO grid?"

For customers that are connected to a transmission system other than Western's, PG&E's or the ISO grid, Western will pass through to that customer the cost to deliver BR over the system to which the customer is connected. An example would be a BR customer connected to SMUD's transmission system. In that case Western would pass through to the BR customer the cost for using SMUD's transmission system to deliver Federal power to that customer.

9. We request to meet with Western, so that we can further understand the proposed rate structures using real numbers appropriate to our agency. We recommend that Western hold informal technical meetings to share in more detail the informal rate proposal.

At the informal rates meeting, Western provided data that customers could use to estimate their costs for products and services purchased from Western. This data is also available on Western's web site. Western does not have any better or additional data available at this time. If more information or better data becomes available in the near future, Western will include such data in the formal rate process.

10. How will Western fund the 130 GWH power purchase to meet project use loads when CVP generation is not sufficient?

Western intends to use FY03 Purchase Power and Wheeling authority to fund the 130 GWH purchase. A decision on the type of funding has not been made.

a. Related to the 130 GWH purchase to meet project use loads, please provide confirmation that Western has a written or otherwise irrevocable agreement with the preference customers to fund all the power purchases needed to meet that project use need and that no such costs would be suballocated to the project use loads for recovery. If such an agreement cannot be obtained, please comment as to other options Western can offer to assure that energy is available for meeting project use needs.

Western has several options for funding project use purchases, including use of receipts, advance funding, Federal reimbursable authority, or other Federally approved funding mechanisms. The type of funding used for purchases to meet project use load will depend on Western's budget authority and contractual arrangements in place at the time of the purchase. Costs to be paid by the CVP water customers (project use) will be determined through the cost sub-allocation.

b. What assurances or other contractual documents/guarantees will be needed to ensure availability of the necessary power (whether funds or self-provided power from Preference Customers)? Are there agreements in place(or soon to be) that will assure CVP water customers that these purchases will be made? What assurances do you anticipate will be needed to guarantee that funds are available to make the deficit power purchases?

Western intends on acquiring the necessary power for project use through purchases, exchanges, self provision or other means.

11. Given the fact that DWR has explicitly acknowledged that the Long-Term state contracts were entered into to serve retail customer loads only, is it justifiable that any exit fee costs should be passed-on to project use loads? Please clarify the positions of Western and PG&E regarding charging exit fees for CPP and other Western products for different Western customer types including project use. Perhaps a table would be useful showing Western's and PG&E's respective positions on charging Exit fees by customer type and product type.

PG&E's position is that exit fees apply to non-CVP hydro power deliveries and any new customers after 1993. Western does not agree with PG&E's position. If Western is charged exit fees for project use power, the disposition of these costs will be determined through the cost sub-allocation. **UPDATE**: Per the Response of PG&E to CVP

Preference Power Post-2004 Implementation Group Motion for Clarification in CPUC Rulemaking 02-01-011 filed June 19, 2003, for existing Western customers, exit fees will apply to load that was served under a PG&E retail tariff on or after February 1, 2001.

12. Will the Federal Control Area include canal-side loads south of Tracy? Which project use loads in the Westlands Service Area are currently covered under 2948A?

This question is outside the scope of Western's informal rate process.

13. Is it possible to have deviations for smaller canal-side project use loads aggregated with larger project use facilities such as Dos Amigos, San Luis, and/or Tracy? Do current and/or anticipated service areas allow for this?

This question is outside the scope of Western's informal rate process.

14. A customer would like more information about the shape of the 130 GWh. Will the purchase be a CPP or will it be added to the BR? If it is a custom product, will it be deemed Federal power?

The purchase will not be CPP nor will it be added to the BR. However, if the 130 GWH purchase is not needed to meet project use load, it could be bought as a CPP by Western's PM. If not, it is sold on the market. The 130 GWH is Federal power regardless of whether it is utilized as CPP.

15. At the informal rates meeting Western reported the total BR that would be available using CY01 data was estimated to be 2,978 GWH. The Beck study showed higher energy for average conditions. An entity understood that the total energy available for preference was projected to be 4,000 GWH. What are the projected wet, dry and average hydro energies available for BR? What are the loads for project use and FP?

Using data from Western's green book, the net CVP generation after meeting project use loads are: 2,111,600 MWH for a dry hydro year, 3,495,900 MWH for a long-term average hydro year, and 5,097,400 MWH for a wet hydro year. The historical project use loads are: 795,000 MWH for a dry hydro year, 1,238,900 MWH for a long-term average hydro year, and 1,440,600 MWH for a wet hydro year. The FP customers' total annual loads are about 150,000 MWH.

16. Please define transmission customers.

Transmission customers are entities that have executed a transmission service agreement/contract with Western.

17. Clarify that the charges for third party transmission costs for delivery of Western power on transmission systems other than Western's, PG&E's or the ISO grid, are passed through to the entity contracting for this transmission delivery.

The costs referred to in the above statement will be passed through to the appropriate customer that received the Federal power delivered over the third party system.

18. What "Ancillary Service Markets" was Western referring to in the presentation in response to an attendees question, when it stated that any Ancillary Services deficiencies or excesses could be sold or bought in the "markets".

Western could sell or buy ancillary services from any entity or market assuming the contractual arrangements were in place.

19. If entities connected to Western’s transmission system, such as Redding, Roseville or City of Shasta Lake, or direct connected Non-ISO Grid entities like Sacramento Municipal Utility District, Turlock Irrigation District and Modesto Irrigation District represent a portion of the ancillary service "markets", wouldn't those entities be similarly long or short on ancillary services given similar hydro resource mix?

This question is outside of the scope of Western’s informal rate process.

20. With reference to the preceding question and in contrast, wouldn't Western's direct connect and internal customers be advantaged by the access and choice associated with participation in larger markets like those operated by ISO, to strategically buy or sell, dependent upon the specific entities circumstance, for example, time of year, resources mix, fuel effective or opportunity costs, and fuel supplies, as opposed to relying more narrowly upon self-provision with thermal CTs or CVP hydro?

This question is outside of the scope of Western’s informal rate process.

21. Has Western considered the increased complexity of Northern California Grid operations, in its cost estimates? Specifically the costs associated with multiple control area operation of Path 66 (USF mitigation, loop flow mitigation, path derates and the associated schedule adjustments)?

Western did not include estimates for these costs.

22. If Western's control area option plan is to ask the ISO to operate COI, how were the resultant increased ISO COI path operations costs reflected in the Western rate structures for the various services? What cost associated with ISO COI path operations expense was used in the estimates?

Western did not include estimates for these costs.

23. How would the resultant "seams" issues resulting from interposing an additional control area at COI, be mitigated or managed? How does Western anticipate it will manage it's COI USF mitigation? How does Western anticipate it will manage COI path derates? How does Western anticipate that it will manage COI Scheduling ramifications,

i.e. congestion mitigation at Malin or Round Mountain, given the adjacent ISO control area financial mitigation mechanisms?

This question is outside of the scope of Western's informal rate process. The impact of Western's operational alternatives is addressed in a separate public process.

24. Are all of Western's proposed rates based upon cost causation principles? Do they avoid cost shifts between various types of western United States market participants, in general and specifically with respect to the proposed creation of an incremental Western transmission access charge on the PACI?

Western recognizes and considers the FERC's use of cost causation principles in setting rates. However, Western sets its rates under federal Reclamation Laws, including setting Western's rates at the lowest cost possible consistent with sound business principles. This supports Western's mission of marketing Federal power to ensure the most widespread use. Hence, Western's rate proposals in the informal rate process reflect its statutory requirements for rate setting and providing power consistent with authorizing project legislation.

25. Western stated that the "around $5 million" figure was the cost for the 130 GWH purchase net after project use loads pays their share. How will the amount project use pays be derived? Shouldn't project use rates be part of this rate process? Why aren't FP rates determined in the same manner as project use rates?

A point of clarification is that the phrase "around $5 million" refers to the purchase to support project use loads and not what is net after project use pays their share.
FP customers are preference power customers and as such pay the same rates as other preference power customers. Project use loads are designated by Reclamation and pay the costs resulting from the cost sub-allocation.

26. Does Western envision the term FP "load" as used to determine "percentage share" to mean the kWhs we actually consumed, or the kWhs scheduled, or otherwise accounted for by a control area operator? We assume from the handout that "load" is calculated on an energy basis (kWh or MWh). Is this correct? What specific formula or factors will be used in determining FP Loads? What does Western means by a FP "load"? When Western uses the term load, it is our understanding that Western does not mean an entity's gross load or even net load, but instead is using this term to describe the amount of CVP energy serving that entity's load. Is this correct? Please explain what is meant by the term 'load'.

Load is a customer's metered usage measured in energy. This definition applies to all preference customers, including FP customers.

27. Pending further clarification, the following summarizes what we think the post 2004 charges from Western (excluding transmission) will be to our agency. We would

appreciate it if you would confirm that we have identified all the right pieces, and any help you can give to the potential magnitude would be greatly appreciated.

BR: 2% of $42 million,	
Or	$840,000
SC (Western): (1 load + 1resource) x 365 days x $14, or	$10,000
SC (ISO invoices passed on): are there any guesses?	?
PM: (1 load + 1resource) x 365 days x $28, or	$20,000
Regulation and Frequency Response Service:	
13,000kW average x $0.40 x 12 months (plus purchases)	$63,000+
Energy imbalance: dependent on Western's performance.	?

In the example above, if the customer had contracted with Western to provide SC and PM services, then the first four services are correct. BR could also be interpreted as FP power delivery. If the customer is in the ISO control area, then the regulation and frequency response service and energy imbalance will be provided by the ISO and the cost would appear in the invoices from the ISO that would be passed through to the appropriate customer. If the customer is in the Federal Control Area, then the costs for regulation and frequency response would be based on the 1.5% bandwidth, and the energy imbalance costs would vary depending on the excursions outside of the bandwidth.
Western does not have any additional data regarding magnitude other than the estimated ISO costs provided in Western's response to question number 1.d.3.

28. Will Western take an active roll in fighting PG&E in its efforts to charge exit charges to project use loads for non-hydro power moving through its system to meet project loads?

This question is outside the scope of Western's informal rate process. For an update on PG&E's position on exit fees, please see Western's response to question number 1.d.2.

29. Please provide a crosswalk of the ancillary service activities with the cost sub-allocation summary to be sure cost recovery meets cost allocation expectations. For instance, one could determine that Reclamation's expenses of hydraulic generation would include all ancillary service activities. However, Western's Reactive Supply and Voltage Control is related to transmission expense-operation. The occurrence of double cost recovery or double allocation must be avoided; however, it cannot be validated with the limited amount of information currently available in the rates process. Please provide a cross walk for all Western proposed revenue requirements to the costs shown on the cost sub-allocation summary.

The costs shown on the sub-allocation summary are power O&M costs incurred by Reclamation and Western and reported on the agency's financial statements. All O&M costs allocated to power will either be recovered through the cost sub-allocation or Western's rate process. Revenues from services other than power marketed by Western such as SC, PM, and ancillary services, as well as revenues from project use loads, offset the preference power ARR. Hence, there is no double recovery.

30. Please clarify the wording that indicates 130 GWH purchase is insufficient to meet hourly project use loads.

Based on CY01 CVP hourly generation data that was shifted within the week to meet project use and first preference loads, the 130 GWH purchase combined with shifted CVP generation was insufficient to meet hourly project use loads during November and December 2001.

31. While our comment is not so much rate related, we are concerned over the degree of water and power generation forecast accuracy Western will be expecting from Reclamation in order to execute the seasonal exchange program. It appears that preference customers will need more than 3 months notice of power generation forecast before these customers would have sufficient information to decide their participation in the exchange program (i.e. a forecast of the next seasonal quarter's generation about ninety days before the start of that quarter). Due to the constantly changing demands and constraints on CVP water operations, it will be impossible to accurately predict generation 3 months in advance without a large amount of uncertainty. Is Western contemplating a risk management program to help identify the risk of this uncertainty and, if so, where will these costs be recovered?

Western is not contemplating a risk management program. The seasonal exchange has been changed to a monthly basis instead of a 3 month basis. The risk of participation in the exchange program should be reduced because of this change. Customers will need to assess the value of the participating in the exchange program based on their situation.

32. As is also the industry norm for both retail and wholesale utilities, Western should also consider implementing a customer charge to recover the cost of accounting, meter reading and billing. These costs do not vary significantly based on the size of a customer or its allocation of Western resource and are more appropriately recovered through a single equal charge to each customer.

Western feels it may be complicated to develop and track an accounting, meter reading and billing charge. For example, one customer takes 3 services, has 10 meters read each month, has no trust accounts, and the charges for those 3 services appear on one bill. Another customer takes 2 services, one of which involves 5 bills per month, with one monthly meter read, and three trust accounts. It is more efficient for Western to recover the accounting, meter reading and billing costs through the rate design for the various products and services than to establish a separate charge.

33. There is a widely held belief that Western is required to sell power at cost. Is this not a valid assumption? What authority does Western have in selling certain products from federal facilities above cost and using the revenue to subsidize other products or services?

Western sets its rates under federal Reclamation Laws, including setting Western's rates at the lowest cost possible consistent with sound business principles. This supports Western's mission of marketing Federal power to ensure the most widespread use. Hence, Western's rate proposals in the informal rate process reflect its statutory requirements for rate setting and providing power consistent with authorizing project legislation.

34. Has Western included costs of administering COTP transaction information and handling such information with neighboring control areas in its 2004 rate process? Please explain. Would this cost be different whether or not Western has formed its own control area? Please explain.

Western has not included estimates of these costs in the informal rate process. The impact of Western's operational alternatives is addressed in another public process.

35. An entity reviewed Western's comments on FERC's proposed Standard Market Design (SMD, FERC Docket RM01-12-000), as well as Western's Strategic Plan for FY 2000-2004. This entity notes that Western's transmission rate design subdivides Western's transmission system into three systems and develops rates for each of these three transmission systems. Western charges customers that use more than one of these transmission services separate charges for moving power using each subdivided transmission system. To PG&E this looks like classic rate pancaking. Western's comments to FERC dated January 10, 2003 at pages 14-15 referred to FERC's intent to eliminate rate-pancaking. Western's comment at page 16, supporting FERC's goals states, "All customers should pay the same embedded costs transmission rate for access to the bulk transmission system". PG&E has the following question for response by Western:

Has Western taken FERC's goal of eliminating rate pancaking into consideration of the design of its rates? Please explain the consideration given and the basis for Western's decision to accept or reject FERC's policy goals.

Western considered FERC policy goals when developing its transmission rates. Western believes there is justification for charging separate rates for its three transmission systems, COTP, PACI, and CVP. Western understands FERC's goal of not pancaking rates, however each Western transmission system has different authorizing legislation which can impact the revenue requirement for that transmission system. Additionally, there is not sufficient capacity available on all three systems to facilitate a customer to reserve and use capacity on all three systems. While the ISO is transitioning to a grid-wide transmission access charge, paying that charge allows a customer to go anywhere on the ISO grid. There is not sufficient capacity available on Western's three transmission systems to allow the same kind of access. Finally, the COTP and PACI were built for bulk power transfers into the state. The CVP was built to move CVP generation to Tracy. For these reasons, Western believes it is appropriate to have a separate transmission rate for each of its transmission systems.

36. Please provide an up to date (without any names if it is an issue) organizational chart that shows the details of the TS&D and TSS Desks' functions. Please feel free to include any changes, including the number of personnel, that you foresee developing prior to 1/1/2005.

Western is still evaluating the number of personnel and specific duties required to perform the TS&D and TSS desk functions after 1/1/05. More detailed information will be provided in Western's formal rate process.

ANCILLARY SERVICES

37. Under the Energy Imbalance Service, what is Western's justification for a +/-1.5% bandwidth? Such a narrow bandwidth will be extremely difficult for Western (acting as a portfolio manager) and Western's VR customers to balance each hour. We would suggest that a 3% bandwidth might be more manageable from both sides of the equation. The ISO, under current Metered Subsystem arrangements, maintains a 3% bandwidth. Western has proposed a deviation band of plus/minus 1.5% in which customers may correct load/resource imbalances. We understand the 1.5% criteria was derived from the Western OATT but ask Western to reconsider the narrowness of the proposed band. At a minimum the bandwidth needs to accommodate the need for regulating capacity and include some room for load variation. The 1.5% bandwidth is identical to the regulating capacity estimate leaving no room for load variation.

Western established the deviation band of +/- 1.5% or a 3% total bandwidth (with a minimum of 2 MW) in compliance with Western's OATT. Western is anticipating that control area members will continually attempt to match their loads and resources. By using similar bandwidths for regulation and energy imbalance, Western hopes to provide an added incentive to control area members to accurately forecast and follow their loads.

38. With regard to the SSC&D Service, could you provide some insight into Western's definition of an E-tag? What goes into an E-tag?

An E-tag represents an energy schedule from a generator to load along a particular transmission path for a specified period of time. Anytime an energy schedule changes, either on a prescheduled or real-time basis, the E-tag must be modified and validated. Western is not discriminating between E-tags that exist within a control area and those that cross control area boundaries.

a. How has Western estimated the number of E-tags it would be handling per day?

Western estimated 4 E-tags per day for each customer. Western estimates the number of E-tags to include the following: (1) BR and FP deliveries, (2) Exchange Energy (if separate from the BR schedules), (3) Existing Transmission Contracts (ETC), (4) PACI, COTP and other firm and non-firm CVP transmission sold via OASIS.

b. Our experience has been that an E-tag represents an electronic means of reporting the path for a schedule that crosses a control area boundary, where a schedule represents the start and stop of a particular delivery, which may be one hour, or one month depending on the duration of the transaction. Currently, we purchase the E-tag reporting service from a third party for approximately $1,000 per month. Based on the estimates provided, Western's charges would appear to exceed that amount by 18 times. Perhaps Western could revisit the costs associated with this service, or consider contracting out this service, similar to our current approach.

Western is using validated E-tags as the billing determinant for SSC&D service. However, SSC&D service encompasses more than validating E-tags. As a transmission provider for three projects, one of Western's major functions is to reliably operate its transmission system. The SSC&D service $3.6 million ARR includes a portion of the costs to reliably operate the transmission systems, including costs for the TSS and TS&D desks. The TSS desk is responsible for monitoring the transmission system for congestion, overloading and E-tag validation. The TS&D desk coordinates with maintenance personnel for repairs and clearance issuance.

39. SSC&D and Reactive Supply and Voltage Control seems embedded in the BR ARR, other ancillary services are not. How will the costs of the ancillary services not embedded in the BR ARR be allocated to customers?

In addition to the two ancillary services listed in the question, operating reserves (spin and non-spin) are also included in the preference power ARR. If a customer has contracted with Western for SC service the costs for regulation and energy imbalance will be determined by the ISO tariff and passed through to each customer as if that customer were under a separate SC ID. If the customer is in the Federal Control Area, the customer would pay Western's charges for these services.

a. What is the implication for loads outside of Western's control area?

Loads outside of Western's control area will need to coordinate with their respective control area operator for provision of these services.

b. Do you foresee customers in other control areas paying twice, i.e. to the ISO and Western?

Whether customers pay twice for the ancillary services bundled with the BR and FP deliveries will depend on the other control area operator's requirements for provision of those ancillary services.

c. Can you clarify which entities will be impacted by the ancillary services?

BR and FP customers outside of the Federal Control Area would only be charged for the four ancillary services included in the preference power ARR. Additional ancillary services required for customers outside of the Federal Control Area would be determined by the respective control area operator.

40. Please describe the revenue allocation for sales of excess reserves. Spinning reserve from the CVP in excess of BR reserve requirements, project use and 1st preference needs may be sold at CVP or market rates which is greater. This agency would appreciate Western providing further clarification of its proposal. How are excess revenues applied if CVP spinning reserve is sold above CVP costs?

If surplus reserves are available from the CVP after meeting merchant requirements (BR, FP and project use deliveries), the revenues from the sale of surplus reserves will offset the preference power MRR.

41. Are voltage and reactive control costs already recovered in generation principle and interest costs? If not, how are they recovered?

Voltage and reactive control costs are not recovered in generation principle and interest costs. In accordance with Western's Open Access Transmission Tariff, Western has established a separate charge for recovering the costs of this service.

42. Does the ISO expect energy imbalance to be calculated at each delivery point, the agency's total, or the aggregate of all Western customers that Western is dealing with the ISO on behalf of the customers?

Generally under the current ISO tariff, energy imbalances are charged to the SC for the load based on deviation from scheduled to metered data at the delivery point.

43. On four of the ancillary services offered by Western, a major cost component is listed entitled: cost of generation capability and various cost estimates are offered. How were such costs determined?

Using a FERC accepted model, all capital, O&M, and interest costs are allocated between transmission and non-transmission (i.e. generation) facilities. Depending on the ancillary service, the CVP powerplants were analyzed and assessed for their physical capability to provide an applicable service. The system capability is then multiplied by the generation cost, as determined in the model, to establish a cost of generation capability for the ancillary service.

44. Please reconcile the SSC&D ARR amount of $3.6 million with the cost sub-allocation amount ($4.2 million) provided to/from your staff.

The $4.2 million used in the cost sub-allocation summary is from Western's FY 99 financials and primarily includes the labor associated with the reliability (operations) function. In addition, there are small components of the General Western Allocation and movable property depreciation. The SSC&D ARR of $3.6 million is primarily the cost of supplying this service and includes a portion of the labor costs for the TS&D and TSS desks, computer hardware, software and their annual expenses needed to sustain these two desks.

45. Does the TS&D desk deal with coordinating outages with generators or just perform transmission related activities? Please provide examples of E-tag transactions that may involve project use loads. Where are TS&D costs shown in the cost sub-allocation summary.

The TS&D desk coordinates with adjacent control areas and utilities for real-time outages for both Western's transmission system and the CVP generators. An e-tag would be needed for a delivery of CVP generation connected to Western's transmission system to a project use load on PG&E's system. The majority of the TS&D costs are included in the transmission expense – operations line on the cost sub-allocation summary.

46. How is Western's contribution to Reactive Supply &Voltage Control from the transmission system included in this component?

It isn't. According to Western's OATT, this service is provided from "generation facilities…and are operated to produce and absorb reactive power."

47. What actions will Western undertake if the hourly energy needs for motoring exceed the available CVP generation? How will such costs be dealt with?

One option would be to make an energy purchase. Those costs would be included in the spinning reserve ARR.

48. Please explain the relationship of your proposed kW-mo rate and how it relates to KVAR that usually pertains to reactive supply and voltage control.

The OATT and FERC policy state that reactive supply and voltage control service is necessary for providing transmission service. Transmission service under the OATT is measured in capacity. Since Western is offering transmission service under the OATT, it is appropriate to bill for reactive supply and voltage control service on a kW-mo basis.

49. The proposed Regulation & Frequency Response service rate design is the ARR divided by the regulation capacity provided during the year. Does this rate include that capacity that was reserved or what was used? If based on what was available, undercollection could result. How will regulation capacity actually be measured or determined?

The rate will be based upon the capacity used to provide regulation and frequency response service. The regulation charge will be based on the maximum amount of regulating capacity used by each customer for the month.

50. It is our understanding that ISO at one time did not recognize motoring units as spinning reserve. Has this changed?

This question is outside the scope of Western's informal rate process.

51. Is the spinning reserve rate design based on what is used or what is available?

The rate design is based on the capacity reserved for spin.

52. The market provides spinning reserve in hourly units not months. How has Western determined the market will support spinning reserve sales by month? If an entity needs spinning reserve on the last day of a month does it get 30 days of reserves over two months or reserve for only the last day of the current month? Why would participants purchase spinning reserve from Western on a monthly basis when it is available in other markets for a shorter span?

The spinning reserve rate is expressed in a $/kW-mo rate but the service and rate can be adjusted to a weekly, daily, and/or hourly basis.

53. Western is proposing a charge for SSC&D service based on the number of E-tags. The SSC&D service includes the costs of the TS&D and the TSS desks. Only one function of the TSS desk is related to E-tags. The number of E-tags does not appear relevant to the other functions such as the need for the TS&D desk to coordinate maintenance, issue clearances etc. There should be a direct link between the service provided, the basis of the service costs and the charge that recovers the revenue requirement.

Coordinating outages and monitoring congestion and system overloading are some of the other functions performed at the TS&D and TSS desks. While not directly related to e-tag validation, these functions will affect the amount of transmission capacity available and the reliable operation of the transmission systems. E-tags represent a use of the available transmission capacity. Therefore, there is a relationship between the functions of the TS&D and TSS desks and e-tag validation. Also not all of the costs of the TS&D and TSS desks are included in the SSC&D service.

54. Regulation is shown as being determined by a plus/minus 1.5% bandwidth depending customer load. The WECC and NERC have specific formulas for calculating the regulation capacity a control area needs to provide based on historical records of the hourly variation in load during the past year. The capacity needed has no relationship to a 1.5% bandwidth.

Western intends to use the bandwidth methodology to differentiate between control members who accurately meet their schedules and those who do not. The cumulative amount of all customers' regulation capacity reservations in any hour will comply with NERC and WECC criteria. The bandwidth is simply one methodology for charging for each customer for their regulation reservation.

55. Are the revenue requirements and costs for the six ancillary services included in the $42 million ARR for BR customers or will BR customers pay these charges in addition to their share of the ARR?

The costs for the four ancillary services provided with BR deliveries, SSC&D, Reactive Power and Voltage Control, and operating reserves (spin and non spin) are already included in the $42 million ARR for BR customers. BR customers will pay for additional ancillary services as determined by the respective control area in which they reside.

56. Will FLS or VLS customers be charged the proposed $0.72/kW-month rate for SSC&D services? If so, how will the charges be allocated among individual FLS and VR customers?

The $0.72/kW-month is not a proposed rate. It is was calculated for illustrative purposes only SSC&D charges are included in the ARR for BR and FP power deliveries. For FLS and VR customer BR and FP power deliveries the SSC&D costs will be based on the number of validated e-tags needed for their BR and FP power deliveries, which includes validations for changes to e-tags.

57. What ancillary services will Western provide to FLS and VR customers? Using illustrative data, what is the approximate annual and per unit cost of each service?

FLS and VR customers are provided some ancillary services with BR deliveries. The ancillary services provided with BR deliveries are: SSC&D service, reactive power and voltage control and operating reserves spinning reserve and supplemental reserve (non-spin). FLS or VR customers outside the Federal Control Area will need to coordinate with the control area operator for any additional ancillary services, such as regulation and energy imbalance.

Estimated annual revenue requirements and per unit costs for Western's ancillary services is listed in the table below.

Service	Annual Revenue Requirement	Per Unit Cost
SSC&D	$3.6 million	$60.00/E-tag
Reactive Power & Voltage Control	$2 million	$.07/kW-month
Operating Reserve – Spinning	$3.5 million	$.31/kW-month
Operating Reserve – Supplemental Reserve Service (Non-spin)	$2.4 million	$.19/kW-month
Regulation and Frequency Response (if in the Federal control area)	$2.3 million	$.40/kW-month
Energy Imbalance (if in the Federal control area)	See note below	See note below

For Western's energy imbalance service, accumulated deviations within bandwidth are corrected or eliminated within 7 days. Any net deviations at the end of 7 days (positive or negative) are exchanged with like hours of energy. Over deliveries outside the bandwidth are lost to the system. Under deliveries are charged at 150% of the CVP power cost or actual cost (whichever is higher).

58. Please provide the details of charges for the SSC&D Service.

Assume 4 validated e-tags each day for a 30 day month for a customer. The estimated rate is $60 per e-tag. $60 x 4 tags x 30 days = $7,200 SSC&D monthly cost. $7,200/10,000 kW-mo = $0.72/kW-mo SSC&D component for transmission service rate. The SSC&D component would be added to the transmission facilities component rate of $0.95/kW-mo and the reactive supply & voltage control component of $.07/kW-mo for a total transmission rate of $$1.74/kW-mo.

59. Please provide all the operational, financial and other input Western has considered for recommending a +/-1.5% bandwidth under the Energy Imbalance Service.

Western proposed the =/- 1.5% bandwidth to be consistent with Western's OATT.

BR AND EXCHANGE ENERGY/PREFERENCE POWER ARR

60. It does not seem like sufficient details have been provided to fully understand how the seasonal or daily exchange programs may work with regard to rates. For example, if Western spreads the cost for the base resource around to various months (rather than on a flat rate), how will the rate differences be handled? Or how are the hourly energy costs of energy that may be PUT to a customer beyond its base resource allocation handled if one participates in the hourly exchange program? Western has stated that Customers' power bills will be adjusted to reflect transactions into and out of the Hourly Exchange Program. How will the bills be adjusted for the customers that have allocations in excess of their hourly loads (providing customers), and those that are allocated a share of the Hourly Exchange Program power (receiving customers)? What is the mechanism or formula that Western will use to determine the level or amount of such adjustments?

As Western allocates more BR costs to the months in which there is more CVP generation, each BR customer would pay their BR percentage of the MRR for any particular month. The customer's BR percentage will be adjusted by the amount of exchange energy provided to the exchange program if another customer used (received) the exchange energy. The customer's BR percentage will also be adjusted if a customer uses (receives) exchange energy. Western anticipates netting all of the hourly exchange energy provided to the exchange program and exchange energy used (received) for the month and determining an exchange energy percentage. This calculation of an exchange energy percentage will be done for each customer that provided or used (received) exchange energy during the month. For example, at the end of the month if a customer has a BR percentage of 5%, uses all of its BR and uses exchange energy that increases its percentage share of BR by 2%, then the customer would pay 7% of the MRR.

61. Does the power O&M costs used by Western in its calculation of a $42 million preference power ARR reflect the cost sub-allocation workgroup's recommended methodologies and cost-sharing formulas for the allocation of CVP power function O&M costs between preference power and project use loads, including a share of half the long-term costs for deficit power purchases?

Yes, with the exception of "half the long-term costs for deficit power purchases." For this exception, Western used the amount the O&M cost sub-allocation workgroup tentatively agreed to, which is roughly $340,000.

62. Is it correct to say that since operating reserves from generation firms up the CVP deliveries, and as such there should be no additional costs for "firming" the CVP deliveries? If not, why not? It is not correct to say there are no additional costs for firming CVP deliveries.

Operating Reserves are provided with BR and FP deliveries, but a separate charge is assessed for loading the reserves.

63. Does the BR ARR already cover all CVP generation costs, in which case reserve charges should not be needed and any sales of these should go to reduce the BR ARR? It appears that Western intends to sell spinning reserves from the CVP in excess of BR reserve requirements, project use and FP needs at CVP rates or market rate whichever is greater.

The BR ARR does not cover all CVP generation costs. The BR ARR was reduced by estimated revenues from other services, including those that are provided from CVP generation resources.

64. According to the BR contracts, the CVP BR includes both the CVP and Washoe Projects. Please explain how the Washoe Project generation is included in the BR capacity and energy amounts. How are the Washoe Project O&M costs included in Western's preference power ARR?

The energy balance in the Washoe account (after project use loads have been met) as of March 31 of each year could be sold to the CVP, increasing the amount of BR. Washoe expenses not recovered through revenues from the Washoe Project, will be added to the CVP preference power ARR.

65. Would it not be more appropriate if Western did not refer to "existing purchase power contracts" as being part of the definition of BR, since Western recently terminated its only remaining power-supply contract? Our understanding is that there are no existing purchase power contracts since the termination of the Enron contract and that

Western is using this definition from our BR contract. Please confirm that there are no existing contracts in our BR and that (aside from the 130 GWh purchase) in the future Western purchases will be exclusively custom products. In the context of the definition of BR taken from the 2004 Marketing Plan, please define existing purchase power contracts and certain ancillary services.

There are no existing long-term purchase power contracts in the BR. However, future Western power purchases will not be exclusively for CPP. In addition to the 130 GWh purchase for project use loads, additional purchases may be made to meet project use loads and for firming BR for the active hour and the next hour. Under the 2004 Marketing Plan, existing purchase power contracts refers to Western's purchase power contracts in existence on 1/1/05. The term certain ancillary services refers to ancillary services that may be needed to support the operational alternative that best meets Western's and its customers needs.

66. Western has stated that all Customers are eligible to contribute to the Seasonal Exchange Program (one to three months) if their anticipated load during that season is less than their anticipated BR amount. Since only customers with seasonal surpluses can make seasonal exchange contributions, will a customer's anticipated load during a season have to be less than their anticipated BR amount, for every hour during the season? What happens if a customer's actual load half way through a season becomes <u>greater</u> than their adjusted BR amount? At what point will Western permanently reallocated power that is surplus to a customer's load?

This question is outside the scope of Western's informal rate process.

67. How did Western determine the costs for BR firming placed into the ARR? Has Western examined the merits of holding back capacity to provide firming, vs. just de-facto buying imbalance energy as replacement power is needed? Is this reducing the amount of capacity and energy that could be available to customers?

Western reviewed recent historical transmission line outages and generator outages (by plant) and assumed two hours for each outage that occurred. Western then multiplied an estimated market rate, the total number of outage hours, and an estimated MW loss associated with the outage to estimate a total cost for firming CVP BR. Firming procedures will be developed by Western in coordination with Reclamation prior to January 1, 2005.

68. Western states that a Customer's BR percentage will be adjusted on a monthly basis for Hourly and Seasonal Exchange Energy (as appropriate). Is not a customer's BR percentage only adjusted for seasonal exchanges? It would be helpful to have more information on how Western plans to make the adjustments to the BR percentage and how the associated costs are allocated due to an exchange. Please give examples clarifying how BR % will be adjusted on a monthly basis. Will one BR customer's costs go up if another BR customer allocation is decreased even if the first BR customer does not receive exchange power?

If a customer is participating in the Seasonal Exchange Program, their BR percentage is changed during the time they are participating in the Seasonal Exchange Program. Under the hourly exchange program, a customer's BR percentage is adjusted for billing purposes at the end of the month to reflect the customer's provision or receipt of the hourly exchange energy during the month. In the hourly exchange program, if Customer A's BR amount exceeds its load in any hour, the excess goes into the hourly exchange program for Customer A's group in that hour. If Customer B uses that exchange energy then Customer A's BR percentage would decrease and Customer B's BR percentage would increase by the same amount. If no preference customer could use Customer A's BR put into the exchange program, then Customer A would NOT have an adjustment to its BR percentage and is still responsible for the BR costs associated with its BR percentage. The unused exchange energy would be sold to the market and the revenues would be used to reduce the BR MRR for Customer A's group.

69. Western states that, "Distributing the BR ARR by putting more costs in months when there is more CVP generation (i.e. Apr to Sep) moderates the monthly per unit cost ($/MWH) fluctuations through the year and supports participation in the exchange program." It is important that such a redistribution plan does not result in cost shifting among customers; that is, each of the BR customers should pay their share of the BR costs per fiscal year, whether or not the redistribution plan is implemented by Western, irrespective of the customers' load patterns. Will such a redistribution of BR ARR result in cost shifting among customers? Will a redistribution of BR ARR coupled with the exchange program create an opportunity for a customer to shift costs to/from low value/load months to/from high value/load months?

No, the redistribution of BR ARR should not result in cost shifting among customers. Each customer will pay their share of the MRR based on their BR percentage, adjusted as appropriate for energy provided to or received from the exchange programs. Under the hourly exchange program, a customer's BR percentage is adjusted for billing purposes at the end of the month to reflect the customer's provision or receipt of the hourly exchange energy during the month. For the hourly exchange program, a customer that puts energy into the exchange energy program will only have their BR % decreased if another preference customer is willing to take the energy. If a preference customer signs up to receive energy from the hourly exchange program, they must do so if they have load. If no other customer is willing to take the energy, the customer providing the energy does not have their BR percentage adjusted. If a customer is participating in the Seasonal Exchange Program, their BR percentage is changed during the time they are participating in the Seasonal Exchange Program. For the seasonal exchange program, a customer can give up BR only if they demonstrate and Western agrees they do not have the hourly load to take their share of BR, and Western determines that this power can be beneficially used by another customer(s).

70. It would also be helpful to have a better understanding how the redistribution of BR ARR would support the exchange program. It is recognized that by putting more costs in months when there is more CVP generation does have the effect of levelizing the

imputed monthly energy rates throughout the year, which will help moderate any cost shifting resulting from the exchange program; however, it appears that the even with such adjustments to the imputed monthly energy costs, there still is an opportunity for a customer to shift costs to/from low value/load months to/from high value/load months via the exchange program. Will the redistribution of BR ARR encourage participation in exchange program? If so, how?

Western believes the redistribution of ARR should result in monthly rates that are closer to market rates through out the year, which will make the exchange energy more valuable to customers.

71. Would the amount of dollars collected from each BR customer over a yearly period be impacted by a plan to shift BR ARR from the Oct to Mar period to the Apr to Sep period, excluding any impacts due to the exchange programs?

If the impact of the exchange programs is excluded, the total amount collected from each BR customer on an annual basis would be the same regardless of the redistribution the BR ARR.

72. Why not apply the revenue from the market sale of exchange energy to the contributing customer's percentage of BR ARR, rather than just forgive the surplus customer and spread the risk to the pool. In the example where Western sells the unwanted exchange energy into the market, is the donor still responsible for paying the MRR or ARR for that power? If not then it makes sense to use the revenue to reduce group costs. If the donor has responsibility for paying the imbedded costs, it would seem fair that the donor is reimbursed up to those costs by the market revenue from the sale. Market revenue in excess of MRR or ARR should go to pay group costs.

By law, all revenues from the sale of CVP power are placed into the Reclamation Fund. Such revenues cannot be directed to individual entities. If a customer's BR is put into the exchange program, the customer BR percentage is not decreased unless another preference customer takes the exchange energy. In the case where the exchange energy is sold into the market, the customer that provided the BR to the exchange program would <u>not</u> have their BR percentage adjusted (decreased). As a result, the customer group is not at risk. In fact the other customers will receive some benefit from the market revenue since it will reduce the group's BR MRR.

73. In spreadsheets submitted last year, Western showed the preference power ARR at $84 million and an estimated annual per unit cost of $25/MWh. At the Informal Rates meeting the preference power ARR is $42 million (after project use pays about $20 million) resulting in a rate statistic of $14/MWh. Please explain the difference between the $84 million and the $42 million. Do these costs include ancillary services and CVP transmission revenue requirement?

The difference between the $84 and $42 million is generally due to three things: 1) purchased power costs have decreased by $16 million due to termination of Enron contract and a reduced level of project use support purchase; 2) reduction of $5 million in annual investment payment and interest expense; and 3) increase in revenue credits of $21 million due to increase in CVP transmission rates, project use revenues and revenues from sales of ancillary services. The preference power ARR of $42 million includes costs for operating reserves (spin and non-spin), SSC&D, reactive supply and voltage control, and Western's CVP network transmission service for delivery of BR and FP power.

a. Please provide a table breaking down the different components and revenue requirements.

The CVP transmission revenue requirement included in the BR and first preference ARR is about $10 million. A breakdown of the components in the CVP transmission revenue requirement is included in questions 86 and 87. The total revenue requirement for operating reserves (spin and non-spin) is about $5.9 million, of which O&M is about $4.3 million, interest and investment payment is about $.5 million, and cost of motoring unit/loss of energy due to efficiency of unit is about $1.1 million. The total revenue requirement would be included in the BR and FP power ARR as well as any offsetting revenues from the sale of surplus reserves. The reactive supply and voltage control revenue requirement included in the BR and first preference ARR is about $450,000, of which O&M is about $375,000 and the rest is interest and investment payment. The SSC&D revenue requirement included in the BR and first preference power ARR is about $3.2 million, which consists entirely of O&M costs.

74. A customer can support shifting BR ARR if Western can show that there are no impacts on the agency's ARR. We request that Western create examples to clarify the process used to weight the months of April-September and allocate the ARR into new MRRs. This customer would also like to see the impact illustrated regarding the MRR. The intent is to reduce implied rates at the expense of increasing MRR in peak months. Please explain the benefit desired, i.e. do implied rates impact entities more than MRR?

In evaluating the shifting of the ARR to higher generation months, the first step was to divide the $42 million ARR by 12 to calculate a monthly implied rate by distributing the ARR evenly throughout the year. Using CY01 data to estimate what BR energy would be available each month by hour, the monthly implied rates had huge variances. To encourage participation in the exchange program and minimize rate fluctuations to the customers, Western shifted costs to the April to September time frame. The amount of ARR shifted was determined by: 1) keeping a minimum cash flow in the Oct to Mar time frame and 2) levelizing the implied monthly rates to the extent possible. The MRR before shifting was $3.5 million. After the shift the MRR ranges from $1.85 million to about $6 million. The implied rates have no impact on the costs paid by any power customer, since billing is based on the FP percentage share of MRR and BR percentage of the MRR.

75. Western stated that the preference power ARR includes costs for CVP transmission

service. Are costs for non-CVP transmission recovered in the preference power ARR as well? What project use energy costs are included in the preference power ARR?

The costs for non-CVP transmission, such as COTP costs, are recovered through sales of transmission service on these facilities. To the extent the full costs of COTP are not recovered through transmission service, the costs are included in the Power ARR. Costs for use of a third party's transmission system such as PG&E's were not included in the preference power ARR. There are no project use energy costs in the estimated preference power ARR of $42 million. Project use energy costs are not recovered through Western's rates.

76. Please provide assurances that the proposed preference power MRR concept will not negatively impact the cash flow needed to fund CVP activities under the Agreement for Operations and Maintenance for CVP Power Facilities.

One of the factors Western considered when analyzing the shift in MRR was the funding needed for Reclamation's and Western's O&M activities.

77. Please explain why the costs for CVP Transmission Service for BR are included in the BR charge. As is the industry norm, this agency believes Western should unbundle the transmission and generation components in the BR rate. Unbundling provides a clear comparable cost for each service and facilitates retail utility accounting and rate making.

Some CVP generating resources are not connected to Western's transmission system. However, CVP power is a system sale, i.e. CVP power can be delivered from any CVP powerplant. To ensure equitable treatment of all CVP customers, regardless of the source and location of CVP power, Western has included the cost for CVP network transmission service in the CVP power ARR.

78. Is the $25.6 million CVP Transmission Service charge already included the $42 million power ARR?

Roughly $10 million of the CVP transmission ARR is included in the $42 million preference power ARR.

79. Western's power ARR for preference power customers is approximately $42 million.

a. Confirm that this figure includes the power ARR for FP Customers but excludes the power ARR for Project Use.

The power ARR for all preference customers, including FP, is approximately $42 million. This power ARR does not include project use costs.

b. What is the total power revenue requirement that corresponds to this figure?

The total annual power costs are about $81 million. Revenues from project use, transmission, ancillary services and other services reduce the total power ARR to $42 million for the preference customers.

c. How is the Project Use share of total power revenue requirement determined?

The project use power costs are determined through the cost sub-allocation.

d. How would the Project Use share of the total power revenue requirement change in a wet and a dry year?

It is very difficult to predict the change in the project use costs due to a wet vs. dry year. The cost sub-allocation consists of several formulas, each containing several variables. These formulas are then applied to costs that can vary, i.e. ISO related costs. The application of these formulas to various cost categories determines the amount of costs that the project use customers pay. A dry vs. wet year is only one of the variables in the cost sub-allocation formulas. Wet vs. dry year does not affect every formula. Also the cost sub-allocation methodology has not been finalized so Western is unable to provide this data at this time.

e. Using illustrative data, what would the ARR for preference power customers be in a wet and dry year?

The preference power ARR is estimated to be $42 million, regardless of the type of water year.

80. Using illustrative data, provide a monthly breakdown of Western's $42 million preference power ARR. Include a monthly breakdown of O&M, repayment, firming purchases, transmission revenue requirements, other.

Western has not developed a monthly breakdown of the costs included in the $42 million. For the Informal Rates meeting, Western divided the $42 million preference power ARR by 12 to estimate a preference power MRR.

81. Western indicates that fluctuations in the monthly unit cost of BR could be reduced by putting more costs in months when there is more CVP generation (i.e., Apr to Sep).

a. What categories of costs and what percentage of the ARR for BR customers could be shifted in this manner? What are the limitations on Western's ability to shift costs from one month or season to another? What is the maximum amount that could be shifted assuming crediting and collections for O&M funding? Assuming no crediting and collections for O&M funding, what is the maximum amount of costs that could be shifted to the April to September period?

All cost categories contained in the BR ARR could be shifted. The percentage of the BR ARR that can be shifted is limited to allow maximum usage of all Federally approved funding mechanisms and accommodate quarterly reporting requirements established by DOE. The O&M collections and crediting could be adjusted to fit the shifted BR ARR. For the Informal Rates meeting, roughly 25% of the BR ARR was shifted to the April to September time frame.

b. Can costs be shifted from one Fiscal Year (FY) to another?

No. The costs must be repaid in the year they are incurred to meet project repayment obligations.

82. Western states that the shifting of BR ARR would not affect the percentage of costs paid by FP customers. Would shifting of BR ARR affect the percentage of ARR paid by the FLS and VR groups? If yes, please explain. Would shifting of the BR ARR affect the percentage of BR ARR paid by individual FLS or VR customers? If yes, please explain.

The shifting of the BR ARR within the year does not affect the percentage of costs that a group of customers or individual customers would pay, whether it is a FLS or VR group or customer It does not affect the amount of costs a customer would pay just the timing of the payments, e.g. payments would be higher in the April to September time frame and lower in the October to March time frame.

83. Western provided two options for the BR rate, equal monthly payments and monthly payments in relation to expected generation.

a. Is Western proposing that each customer may choose the option it prefers?

No, Western will not provide differing options on charging for the Power RR to each individual customer. All customers will pay using the same option. After evaluating comments from customers, Western will determine which option to use for collecting the preference power ARR.

b. Would the rate option that collects revenue in proportion to generation create additional cash flow problems for Western by starting the federal fiscal year with low monthly revenues during lower generation months?

While Western continues its cash flow analysis, it is believed that this rate option will not have an adverse impact as long as Western is authorized sufficient reimbursable and use of receipt authorities. In order to minimize adverse impacts to cash flow, advance funding for O&M will likely need to occur during the periods of higher generation.

84. Assuming BR ARR shifting goes into effect, wouldn't one be discouraged from participating in the Exchange program during the heavier weighted months, i.e. increasing their effective BR % during July where ARR will be heavier weighted?

While the BR ARR is more heavily weighted in July, the higher generation available will likely cause the per unit rate ($/MWH) to be near or below the market during July.

85. Please provide the details (and an example) of how a customer's percentage of the BR changes and how that percentage is applied to the BR MRR when that customer participates in a exchange program.

Please see example below on how BR MRR and BR percentage changes by customers' participation in the exchange program.

Western's								
MRR = $30			Hourly	Contribution	Customers			Customer's
		Customer's	BR =	to	Wanting	BR	Revised	Revised
	BR %	MRR	30 MWH	EP	EE	delivered	BR %	MRR
Customer A	20%	$6	6	3	0	3	10.00%	$3
Customer B	10%	$3	3	0	1	4	13.33%	$4
Customer C	70%	$21	21	0	2	23	76.67%	$23
Total		$30	30	3	3	30	100.00%	$30

CVP TRANSMISSION

86. Western states that the ARR for CVP transmission facilities is about $25.6 million.

a. Provide an approximate monthly breakdown of the transmission ARR.

The approximate monthly breakdown of the transmission ARR is $2.13 million per month (transmission ARR/12 months).

b. Approximately what percentage of the transmission ARR is related to facilities

(a) between 60 and 115 kV;

There is one facility that is below 115 kV.

(b) between 115 and 230 kV;

Approximately 99% of the CVP transmission ARR is related to facilities at or above 115 kV.

(c) over 230 kV?

There are no facilities above 230 kV in the CVP Transmission ARR.

c. Approximately what percentage of the CVP transmission ARR would be paid by FLS and VR customers, respectively?

It is not known at this time how many FLS and VRS customers there will be, so it is not possible to separate the CVP network transmission service costs into FLS and VR percentages. The CVP transmission ARR is recovered through: CVP network transmission service, point to point transmission service (i.e. ETCs), and short term sales of CVP transmission. Both FLS and VR customers receive BR, so these customers would pay a portion of the CVP network transmission service cost for the BR based on the individual customer's BR percentage. The remainder of the transmission ARR would be recovered through the ETCs and sales of short term CVP transmission.

Estimated CVP Network and ETC transmission costs	
Firm Pt-to-Pt ARR ($)	$14,869,779
Firm Pt-to-Pt Load under contract (12 kW-months)	15,720,000
Estimated rate ($/kW-Month)	0.95
Network Transmission ARR ($)	$9,876,296
Network Transmission Load (12 kW-months)	10,440,000
Estimated rate ($/kW-Month)	0.95

87. Could Western provide more detail on the cost allocations for the CVP transmission rate? For example, what is the breakdown of the fixed vs. O&M?

16% of the CVP transmission ARR is fixed costs, the remaining transmission ARR is O&M.

a. What are the components of O&M that make it 84% of the total annual transmission cost?

The CVP transmission O&M includes; administrative & general costs, directly charged transmission facility O&M costs, and general O&M costs that are not directly charged to a facility. These general O&M costs are allocated to the transmission function based on a ratio of transmission plant to total plant.

b. What is Western using for the billing units?

CVP network service is based on the rolling average of the twelve monthly CP for the CVP generation connected to the CVP transmission system. Customers will be billed for network service through their BR and FP percentages of the preference power ARR. A $/KW-month charge is used for ETCs and OATT Point-to-Point transmission service, based on transmission capacity under contract.

c. Does Western consider network and point-to-point to be charged at the same rate?

The CVP transmission formula rates take into account both network and point-to-point transmission service when allocating the ARR. The outcome is that network and point-to-point transmission service result in a comparable rate.

d. Please provide a table of the various transmission costs components (i.e. O&M, debt repayment and billing units) that were used for the $0.57 existing rate along with the estimated components for the proposed $0.95 rate.

Table of cost components for current and proposed CVP point-to-point transmission rate is shown below.

	2001 rate case ($0.57/kW-Month)	Post 2004 rate case ($0.95/kW-Month)
Annual Cost Components ($)		
O&M, A&G	$16,005,428	$21,587,310
Depreciation	$3,240,776	$2,629,683
Interest	$1,314,700	$1,350,701
Subtotal	$20,560,904	$25,567,694
Credits	-$3,767,940	-$821,619
Net Annual Costs	$16,792,964	$24,746,075
Denominator (kW-Months)		
CVP Northern Plants (network)	15,144,000	10,441,000
ETC TRD	14,421,000	15,720,000
	29,565,000	26,161,000

88. Why is the proposed CVP point-to-point Transmission rate almost double the present rate?

The CVP Transmission rate increase is the result of an increase in O&M charges to the transmission function and the decrease in the CVP Transmission rate formula's denominator. The increase in O&M is due to an increase in Western's overall O&M expenses for implementation of the 2004 Marketing Plan and an increase in the direct assignment of O&M to facilities that support the transmission function. The proposed

CVP Transmission formula rate's denominator is based on the rolling average of the 12 monthly CP of the CVP generation connected to the CVP transmission system. Under the current CVP transmission formula rate, the denominator contained the maximum CP of the CPV generation connected to the CVP transmission system. By using the rolling average 12 monthly CP, the denominator is smaller under the proposed rates than under the current rates.

89. Are the non-direct connected CVP delivery and ISO costs for BR included in the ARR for CVP transmission facilities? If so, it appears that would represent a cost shift that violates cost causation. It would appear that according to the cost sub-allocation workgroup's recommended methodologies and cost-sharing formulas, the CVP Water Users would pay the project use transmission costs. Likewise, it would seem logical that the non-direct preference customers should pay the transmission service costs related to delivery of the non-direct customers' BR. The non-direct preference customers would pay Western's estimate of embedded costs.

The ARR for CVP Transmission service includes the costs for Western's CVP transmission facilities only. It does not include any ISO/PG&E transmission system costs.

90. Will the customers' taking CVP transmission service under existing contracts have the network component included in their rates after 2004 during the term of their transmission service contracts?

Yes. Starting 1/1/05, the rate denominator for the firm point-to-point transmission rate will include the rolling average of the 12 monthly CP for network transmission service as well as the reserved transmission capacity for ETCs and point to point service under the OATT.

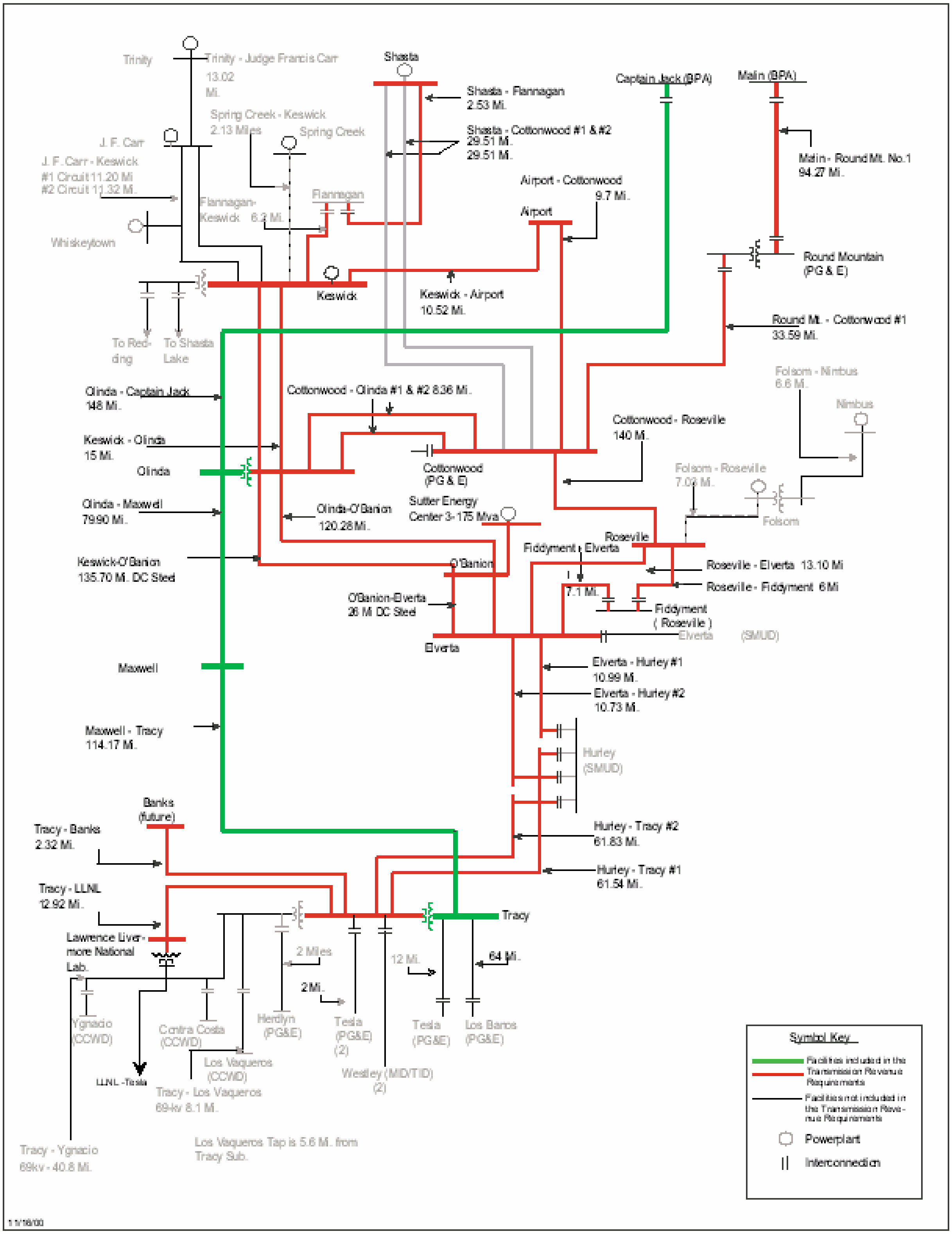
91. Please provide examples of facilities that support the transmission function.

An interconnected group of transmission lines and associated equipment for the movement or transfer of electric energy between points of supply and points at which it is transformed for delivery to customers or is delivered to other electric systems. Facilities that support the bulk transfer of energy i.e. transmission lines at 230kV and above, substations, and high side transformers. (See facilities map in question 92)

92. Western is estimating a transmission rate of $0.95/kW-mo. which on its face is a 67% increase over the existing rate. With such a substantial increase Western should provide a detailed cost of service that enables customers to determine whether the proposed rates adhere to a just and reasonable standard when applied to a particular customer. Cost causation should be the driving principle in Western=s transmission rate design. This customer expects Western's rate process will enable it to understand in detail how any cost increases it incurs from the new rates are determined and whether the Western's transmission costs are being fairly allocated. With this objective in mind, please provide … data that shows:

a. A list of the facilities that support the transmission function to which O&M costs are being directly charged.

See map below.



b. Please provide a detailed breakdown for all components including O&M that comprise Western's estimated ARR used in calculating both the proposed rate and the current rate.

A breakdown of the cost categories included in Western's O&M expense are listed in the responses to questions 92.c and 92.d. The cost categories for Western's O&M are the same for the current and proosed rates. The other major cost categories are in table in question 87.

c. For the proposed rates, a breakdown of O&M components and their associated costs that are being directly charged to facilities.

Around $3.1 million was direct charged to transmission facilities. Examples of O&M components that are direct charged to facilities are:

- Labor costs (including some indirect costs)
- Travel
- Training
- Contract costs
- Warehouse/stores costs

d. For the proposed rates, a breakdown of O&M components and their associated costs that are NOT being directly charged to facilities.

Around $18.4 million of O&M costs was not directly charged. Examples of O&M components not directly charged to facilities are:

- Indirect labor costs
- Travel
- Training
- Contract costs
- Warehouse/stores costs
- Regional and corporate offices costs

e. On what basis are O&M costs that not directly charged to a facility allocated between transmission and generation?

Generallly, O&M costs not directly charged are allocated to transmission based on the ratio of plant in service that supports the transmission function to Western's total plant in service.

f. Please provide details on the derivation of transmission capacity (kW-mo) provided during the year that Western used in the denominator for calculating the rates. How was the capacity (kW-mo) associated with each customer (including project use) that receives CVP Transmission Service determined?

For CVP Firm Point-to-Point Transmission service (including ETCs), the capacity reserved under the contract (kW-mo) is in the denominator. The capacity in the denominator for the network transmission service is the rolling average of the 12 monthly CP of the CVP generation connected to the CVP transmission system. The network transmission service includes BR, FP and project use deliveries over the CVP transmission system.

g. Will Western provide a separate detailing of the CVP Transmission Service charge to the customer?

A separate line item will appear on the bill for those customers taking firm point to point transmission service. For BR, FP and project use customers there will not be a separate detailing for the CVP network transmission service.

93. Please provide the details of how the CVP transmission rate would be applied to the ETCs (which is point to point) versus how that rate is applied to network service for CVP generation. Please provide the details of charges allocated for the BR transmission rate.

The rate for ETCs will be applied in accordance with the Firm Point-to-Point rate formula which has three components; transmission facilities, SSC&D, and Reactive Supply and Voltage Control. The resulting rate will be charged on all reserved capacity under the ETCs. For the delivery of the BR and FP power, the same three components (transmission facilities, SSC&D, and Reactive Supply and Voltage Control) will comprise the costs for delivery of the BR. These costs will be included in the preference power MRR. The FP customers' percentages will be applied to the preference power MRR to determine the MRR for the BR. Each customer's BR percentage is applied to the BR MRR.

CAMS

94. For loads located outside of Western's control area, will customers have to subscribe to two CAMS/GMCs?

Not unless the customer has loads in both control areas. Western's CAMS is applicable only to those customers who are within Western's control area. The ISO's GMC charge applies to those customers who are in the ISO control area.

95. Western is implementing a control area management service (CAMS) charge for customer in the federal control area.

a. Will CAMS be charged to resources as well as load?

No.

b. Will BR for non-control area participants contain a CAMS charge?

No.

96. For CAMS, is the $1.5 million cost of the TSS desk in addition to the TSS costs included in the SSC&D activity?

Yes. A portion of the costs for this activity is contained in both rate designs.

CPP

97. If advance funding is used for a multi-year CPP purchase, will Western require customers to advance the full value of the purchase or will customers be able to advance fund their share of the energy on a monthly basis?

Advance funding of a multi-year purchase would require the customer to advance the full amount of the purchase for all years.

98. Please clarify whether or not CPP will be subject to PG&E exit fees as you understand it. I have heard yes and no from Western representatives regarding the interpretation of PG&E's intent. We look forward to a more detailed presentation explaining the impact of PG&E's exit fees on all CVP customers, water and power. A customer is concerned about the wording "existing delivery point(s)". We wish to clarify whether this is meant to imply that a change in delivery point(s) post 2004 would/could mean PG&E mean exit fees charged to a customer? We may decide to take delivery at Livermore 230 kV or some other location in the future.

Western's understanding of PG&E's position on exit fees is: any new customer served by Western after 2005 is subject to exit fees; any existing customers whose delivery points were established between 1993 and 2004, and take supplmenental power from PG&E may be charged exit fees only for Western's power that is not CVP generation, depending on whether or not they were a x/y customer at the time the DWR bond debt was incurred in 2001. **UPDATE**: Per the Response of PG&E to CVP Preference Power Post-2004 Implementation Group Motion for Clarification in CPUC Rulemaking 02-01-011 filed June 19, 2003, for existing Western customers, exit fees will apply to load that was served under a PG&E retail tariff on or after February 1, 2001.

99. Western states that the costs of long-term CPP will be charged to the customer that uses the power.

a. Assuming Western signs a 12-month fixed price contract for a group of 3 FLS customers, how would the costs be allocated to each customer? Will each customer pay a fixed dollar amount of costs on a take-or-pay basis? A fixed percentage of the total cost? Or will each customer pay only for the amount of power that it actually uses? Provide a similar explanation assuming the purchase is indexed to the monthly NP15 price.

The long-term CPP costs for each of the 3 FLS customers will be allocated based on the amount of CPP that each customer uses. Any unused long-term CPP will be sold to the market. Any revenues from selling the surplus CPP to the market will be allocated to each FLS customer based on the number of FLS customers in the group. In this case where there are 3 customers, the revenues would be split 1/3 to each FLS customer. The pricing of the CPP does not affect the cost recovery methodology.

b. What other charges (e.g., transmission, SC, PM, Ancillary services) would customers pay for a CPP and how would the costs be allocated?

If a FLS customer is purchasing CPP from Western, they will also be taking PM service. A VR customer purchasing CPP from Western, is not required to purchase SC and PM services from Western. Any transmission costs for the CPP will be passed on to each customer taking CPP, unless a portion of those costs qualify as ISO/PG&E T&D facility related costs which exceed Western's estimated embedded costs. In that case, those ISO/PG&E T&D facility related costs would be included in the PACI ARR. If ancillary services are part of the CPP, then the costs for those ancillary services will be passed through to each customer taking CPP.

FIRST PERFERENCE CUSTOMER COSTS

100. Will FP Customers be able to participate in the exchange programs? How and why is the first preference customers' allocation different then the remaining preference customers allocation? Why is it not all done as one step the same way?

FP customers will not participate in the exchange program because their entitlement is limited to their load. FP customers would not have CVP power surplus to their needs that could be put into the exchange program nor will they use exchange energy to meet their loads. FP customers do not have a BR percentage because, as a matter of law, their entitlement is a function of CVP generation and their load. FP entitlements are capped, but are not a fixed % like those of other customers.

101. Please give examples of how the FP customers' shares of preference power ARR will be calculated.

For illustrative purposes let's assume for the current month a preference power MRR of $1,000 and the previous fiscal year's load percentage of CVP generation (less project use) for FP Customer A is 1%. The 1% is determined by taking FP Customer A's load for the previous fiscal year and dividing by the CVP generation less project use for the same previous fiscal year. Western intends on multiplying the preference power ARR by 1% to determine the FP Customer A's annual cost. FP Customer A's monthly charge is the annual cost divided by 12.

102. Assuming that all FP entities in a county of origin are limited to the smaller of their load or 25% (12.5 % in the cases of Calaveras and Tuolumne) of the county of origin project's net generation, please add the words "smaller of 1st preference energy entitlement or" ahead of the word load. This agency is concerned that monthly

percentage changes might adversely impact our rates if the ARR is weighted in the April-September period. Please give examples that clarify how FP percentages are used to calculate rates. Please clarify whether Western means fiscal year or trailing 12 months, i.e. I don't understand an annualized FY number that is adjusted every 6 months.

Please see the table below for the calculation for the FP customers' percentage share of the preference power MRR. The same process will be used to develop the percentages for each FP customer. After the FP customers' charges for the year have been determined, Western will then subtract the sum of these annual FP charges from the $42,000,000 preference power ARR to determine an ARR for BR customers. Each customer's BR percentage will be applied against the BR MRR to determine their monthly charge, assuming no exchange program impacts. In the example below, the .322% will be a fixed percent that will be applied to the preference power ARR throughout the FY. Western will evaluate each FP customer's percentage every six months and compare it to the ratio of that FP customer's load to CVP generation less project use for the current FY to ensure that the ratio is close to the ratio that would result using current FY data. If Western determines that the ratio is within an acceptable range then the ratio will continue to be used in calculating the FP customer's monthly power charges. If the ratio is found to be outside the acceptable range then Western will make an adjustment to the ratio to more accurately reflect the FP customer's ratio of load to CVP generation less project use.

Example data/Description		Assumption and Calculation
FP customers total load for previous FY	10,000 MWH	
CVP generation less project use for previous FY	3,100,000 MWH	
Ratio for FP customers % share of MRR	.322%	
FP customers MRR BR MRR	$16,100 $4,983,900	Assume a preference power MRR of $5,000,000.

103. This agency has a concern regarding the FP customers' percentage share of the preference power ARR. Perhaps an example of your proposal, as we understand it, will best describe my concern.

IF:

FP Load in year one is 70 GWh, and
CVP Generation, net of Project Use, in year one is 70 GWh, and
CVP Generation, net of Project Use, in year two is 2,000 GWh,

THEN:

The FP Customer's percentage share for year two would be 100%, and until "adjusted as appropriate," Other preference power customers would receive 1,930 GWH, pay nothing, and after the "appropriate adjustment" it could take years to balance. A similar problem would occur if there were a wet year followed by a dry year. Then FP would be paying far too little, other preference power customers would pay too much, and after six months it could take years to balance. We are assuming that the phrase "review every six months and adjusted as appropriate" is meant to be sure that in the long term, FP pays their "fair share". Meaning that in the long term, FP pays a total of its load divided by total generation multiplied by total revenue requirements. I also assume that load and net generation is kWh only. Does Western concur with these assumptions?

Western concurs that the FP customers should pay their "fair share". To accomplish this, Western's intent is to charge FP customers a percentage of the MRR based on the amount of FP load to CVP generation less project use for the previous fiscal year. Western understands the concern regarding the variability of costs due to wet vs. dry year generation. Western also recognizes that generally the type of water year it is going to be is not known until April, which is 6 months into the fiscal year. Western agrees that load and net generation is kWh only.

104. I am assuming that the term "CVP Generation less project use" for purposes of determining FP "percentage share" means:

CVP Hydroelectric Generation, <u>plus</u>
Both long and short term purchases intended to meet project use and FP loads when CVP Hydroelectric is or is expected to be less than the amount needed to meet project use or FP loads,
<u>plus</u>
Both long and short tem purchases that help shape the Hydroelectric Generation to optimize its peaking capabilities, <u>less</u>
project use's actual load.

All calculations based on energy only. Does CVP generation include power purchases that Western may make to serve project use and/or FP loads? What specific formula or factors will be used in determining CVP generation?

The phrase "CVP Generation less Project Use" is CVP hydro generation, which includes firming for the active hour and following hour, power needed to meet project use and first preference load, less project use metered load. Western will address shaping purchases in the formal rate process. Calculations are based on energy.

105. Have you considered developing the FP "percentage share" based on forecasted figures with a similar adjustment clause? Have you considered developing a formula for a per kWh charge instead of using the "percentage share" approach? I think we would prefer either approach over the "percentage share" based on history. We tend to believe that it would be simpler, fairer, and more reasonable if the charge for FP customers was a per kWh charge that is based on long-term average historical generation (adjusted for the absence of 2948A and other past firming purchases) and the expected revenue requirement. Perhaps a twenty-year rolling average similar to the way the MEFPC is developed. We'll reserve pursuing this idea until we better understand how you propose "adjusted as appropriate" will work.

A per kWh charge would be difficult to implement since all the other CVP power billing is done on a percentage basis. It will be easier to administer FP billing if it is also billed on at percentage basis. Using forecasted data may also present problems in that the type of water year it is going to be wouldn't be known until April, which is more than halfway through the fiscal year. Western is reluctant to use long term historical generation since the current CVP operating constraints and requirements are much different that they were twenty years ago. Whatever the basis that is used to develop the FP customers' percentage share of preference power MRR will need to be adjusted through out the fiscal year.

106. Regarding Western's power revenue requirement of $42 million, Western implies that FP customers' only pay up to a certain amount and that the other customers will pay for costs above the percentage. Is this true? They need to pay all of their costs since they are getting scheduled first.

The estimated preference power MRR applies to both FP and BR customers. BR customers share of the preference power MRR are determined after the FP customers share of the preference power MRR.

107. The equation for determining FP customers share of the estimated preference power ARR does not work. If it is a dry year rather then an average or wet year, FP could get more energy. If they are scheduled first, I don't see why they would need to have this equation. Every six months is too long.

To a large degree, the FP customer deliveries are determined by the FP customers' load, so the amount of energy used by the FP customers isn't affected by an average or wet year. However, the type of water year it is could affect the FP customers' percentage share of the preference power ARR. Western intends on adjusting the FP customers' ratios as necessary in an attempt to ensure that FP customers pay an amount for CVP power that is approximately equal to their share of the CVP power used. If the FP customers take a smaller or larger percentage of the CVP generation that year, then their percentage share of the preference power ARR will be adjusted.

108. Why don't FP customers have their share of the preference power MRR shifted?

FP customers would not have their actual percentage change as Western shifts the ARR just as the BR customers would not have their BR percentage change as Western shifts the ARR. The FP percentage would be applied to the shifted preference power MRR and the preference customers BR percentage would be applied to the shifted preference power MRR.

109. We need a better understanding of Western's proposal for FP customers percentage share of the preference power ARR. Our understanding is that the percentage will be based upon a ratio of our load for the previous fiscal year to the total CVP generation, less project use, for the previous fiscal year. Questions related to this rate concept follow:

a. Will project use contribute to the preference power ARR along with FP and other preference customers? If so, how is the rate determined for project use?

The costs to be paid by project use loads are determined through the cost sub-allocation. The revenues from project use loads are applied to the CVP power revenue requirement and the remaining CVP preference power revenue requirement is collected from the preference customers, including FP customers.

b. Is it possible that the FP Customers share of the power revenue requirement could vary dramatically from year to year? Would dry year and extended dry year conditions influence our share of the power revenue requirement?

It is likely that there will be variations in the 1st preference share of the power ARR because of the variability of the CVP generation and project use requirements. Dry year and extended dry year conditions would influence the FP customers' share of the preference power ARR.

c. If project use loads increased substantially in the future, how would this influence the FP customers' share of the preference power ARR? We would like Western to evaluate the sensitivity of dry year and extended dry year conditions and an increase in project use loads on FP customers' percentage share of preference power ARR using historical hydrology and projected project use loads.

Many variables affect the preference power ARR, such as CVP generation, FP loads, the cost sub-allocation which determines the costs paid by project use load, offsetting revenues from other services such as transmission, etc. Because of all these variables, it is difficult to predict the effect of a single variable. Western does not have the resources to evaluate the sensitivities requested, however using the data in the green book for CVP generation and project use for a wet, dry, and average year, and CY01 FP customer load, the FP customers' percentage share of the preference power ARR ranges from around 3% to 7%.

110. What factors would necessitate Western to review every six months the need to possibly adjust the FP Customer percentage? What advance notice will we receive of such an adjustment?

Changes in project use, preference power ARR and CVP generation would be factors in the FP customers' percentage review. Once Western determines that an adjustment to the ratio is necessary, Western plans to provide at 30 days notice of the change in the percentage share.

111. Please clarify specifically what additional services, above and beyond power, FP customers will need to secure through either Western or others to have the same power product that the FP customers are receiving today. Are any of the costs associated with these additional services part of the FP customers' preference power ARR or are the costs for these additional services separate? If they were separate, what would our approximate costs be for each service?

See question 27.

112. Assuming Western serves as the FP customers' SC and the FP customer loads remain within the limits of the respective entitlements, would there be any situations where FP customers would be subject to paying for imbalance energy?

Yes. Energy imbalance is not based on a customer's entitlement. Energy imbalance occurs when metered energy deviates from scheduled energy. In the ISO control area, the imbalance is measured, calculated, and charged for each settlement interval.

113. Please explain how FP customers will pay to Western their share of the preference power ARR. Will Western invoice the FP customers on a monthly basis as

today and include the cost of any additional services?

Western will send a monthly bill to the FP customers for services provided by Western. For services provided by other entities, such as the ISO, Western will bill the FP customers as often as Western receives those charges, or make withdrawals from a trust account established by the customer with Western.

114. Western has provided its understanding of PG&E's position regarding delivery arrangements for Western's customers. Please explain how Western intends to meet its obligation to provide the sale and delivery of energy to FP customers.

Western is continuing discussions with PG&E on delivery of Federal power starting 1/1/05 to preference customers and project use loads.

OPERATIONAL ALTERNATIVES

115. What ancillary services market and scheduling functionality would be used to buy or sell ancillary services between control areas, and specifically to Western customers that remain located within the ISO? Aren't some Western customers advantaged and others disadvantaged if Western forms a control area, thereby creating two classes of customers, and therefore two classes of services offered, given the limitations to provide these services should Western become an adjacent control area?

This question is outside of the scope of Western's informal rate process. The impact of Western's operational alternatives is addressed in a separate public process.

116. How does Western propose to provide regulation or operating reserves services to the preference and project use loads located out on the PG&E grid, within the ISO Control Area, especially regulation if it becomes a separate control area? Wouldn't the MSS option afford those customers more choice and economic alternatives if Western remains part of the ISO grid and thereby, self-provide regulation services to meet their load obligation?

This question is outside of the scope of Western's informal rate process. The impact of Western's operational alternatives is addressed in a separate public process.

117. Doesn't the Western Control Area option severely restrict the options for various classes of Western Federal power customers to secure either CVP unit based ancillary services or conversely market based ancillary services dependent upon whether or not their load remains within the ISO control area or is situated in the proposed Western control area?

This question is outside of the scope of Western's informal rate process. The impact of Western's operational alternatives is addressed in a separate public process.

118. Aren't Western's ancillary service obligations and costs increased if Western

becomes an independent control area due to Most Severe Single Contingency?

This question is outside of the scope of Western’s informal rate process. The impact of Western’s operational alternatives is addressed in a separate public process.

119. Isn't there a significant loss of ancillary service market opportunity associated with both operating reserves and regulation, should Western pursue the Control Area option over the ISO Control Area Metered Subsystem option?

This question is outside of the scope of Western’s informal rate process. The impact of Western’s operational alternatives is addressed in a separate public process.

120. PG&E requests that Western provide, as part of this rates process a discussion of the consideration Western has given to becoming a Participating Transmission Owner (PTO) and turning over the rights of its transmission system to the ISO. In such a scenario, Western’s customers served from PG&E’s electric system would pay a single transmission service charge for use of the combined PG&E and Western transmission systems. This approach eliminates the significant pancaking of transmission system costs that is embedded in Western’s approach. PG&E believes that Western’s decision not to become a PTO provides a basis on which to determine which customers should pay for the increased costs incurred by Western’s customers served from PG&E’s transmission system. PG&E submits the following questions for response by Western:

a. Does Western agree that its PG&E served customers would see a benefit if Western decided to become a PTO with the ISO? Please explain why or why not.

b. Please explain Western’s evaluation of the impacts to the transmission costs charged to all of its customers if Western was to become a PTO with the ISO.

c. Has Western considered any factors other than the costs and benefits to its customers of becoming a PTO with the ISO? Please explain fully what such decision factors Western has consider in its evaluation to date to join or not join the ISO as a PTO.

d. Which of Western’s customers most benefit by Western’s decision not to become a PTO with the ISO? Please explain.

The impact of Western’s operational alternatives, including becoming a PTO, is addressed in a separate public process.

PACI TRANSMISSION

121. Will BR customers connected to the PG&E grid take transmission service over the PACI? If so, what is the approximate amount of PACI costs that will be charged to FLS and VR customers?

Any entity, including a BR customer connected to the PG&E grid, can contract for transmission service over the PACI. Such entity would pay the formula rate based on their firm point-to-point transmission service under Western's OATT.

122. Regarding ISO/PG&E costs to be recovered through the PACI transmission ARR, Western states that it will provide "estimates of embedded costs". Embedded costs of what?

Western's estimate of embedded costs is an estimate of what customers would pay if the current subfunctionalized rate methodology for deliveries over ISO/PG&E's system was continued after 1/1/05.
15. Western states that starting 1/1/05, customers who have Federal power delivered from the ISO grid or PG&E's system would continue to pay Western's estimate of embedded costs.

a. Define embedded costs and identify the facilities to which this concept applies. (E.g., does the concept apply to Western's share of the PACI, Western's 500-kV system, facilities at 230-kV and below, or all of these?)

The term "embedded costs" is based on PG&E's sub-functionalized transmission rate methodology currently in place under Contract 2948A. "Embedded costs" applies to the facilities included in PG&E's current 2948A transmission rates. "Embedded costs" does not apply to Western's transmission facilities.

b. Which Western customers are currently paying embedded cost rates?

Almost all of Western's preference customers connected to ISO/PG&E transmission facilities are paying transmission rates based on the "embedded cost" for their Western firm power deliveries. There are a few preference customers that pay different rates for transmission service over PG&E's system.

c. What is the total amount of embedded costs currently being paid by customers connected to Western's transmission system?

The term "embedded cost" is for use of PG&E/ISO transmission system. It does not apply to use of Western's transmission system.

d. What is the total amount of embedded costs currently being paid by customers connected to the PG&E system?

For FY02, total "embedded costs" were around $12 million (includes embedded costs for project use deliveries).

e. Where do these show up on customers monthly power bills?

There is a line item on Western's Wholesale Power Bill which is titled Pass-Thru

Transmission Charge.

f. Would customers connected to Western's system pay embedded costs post 1/1/05? Would customers connected to the PG&E system? What is the annual dollar amount expected to be paid by each group of customers?

The term "embedded cost" is for use of the PG&E/ISO T&D systems to deliver Federal power. It does not apply to use of Western's transmission system. The projected annual dollar amount for "embedded costs" to be paid by customers on ISO/PG&E transmission system starting 1/1/05 would vary based on the amount of FP, BR and/or CPP delivered to customers.

123. Please provide a detailed explanation of ISO and PG&E charges that are being proposed to be included in the PACI rate. Who pays these costs? How are these charges billed to Western from the ISO and PG&E?

The costs incurred for delivery of Federal power over PG&E/ISO transmission systems that are facility related costs and more than Western's estimate of embedded costs will be included in the PACI transmission ARR. These costs will be recovered from entities taking transmission service on the PACI. The details for transferring these ISO/PG&E T&D facility charges to Western are not available at this time.

124. Please explain the logic behind the following statements: "The PACI was constructed to ensure that Western would be able to serve its customers at a cost not to exceed the cost of Federal construction. As a result, certain Western power delivery costs are included in the PACI ARR."
The Federal legislation authorizing the PACI intended that Western customers pay costs that would not exceed the cost of Federal construction. To ensure that all Western's customers receive the benefit intended by the Federal legislation authorizing the PACI, certain Western power delivery costs will be included in the PACI ARR.

125. Western should explain what is meant by "facility related costs" in the following statement: "The costs included in the PACI ARR would be limited to ISO/PG&E (T&D) facility related costs only." A numerical example would help. ISO/PG&E rates also vary over time, and can be changed retroactively. What specific costs does Western envision by ISO/PG&E (T&D) facility related costs only?

The phrase "ISO/PG&E T&D facility related costs" means those types of costs that are included in the current 2948A transmission subfunctionalized rate methodology, which includes a credit for Western's facilities. To get an idea of these types of costs, customers can review PG&E's transmission rate FERC filing that supports the current 2948A transmission rates.

126. With regard to the PACI Transmission service, what are the actual (estimated) dollar amounts for the ISO/PG&E (T&D) facilities cost for deliveries of Western power (less embedded costs)? Please show the breakdown between ISO and PG&E. What

are the charges and the allocation units for both the ISO and PG&E Charges? What services does Western receive from the ISO and PG&E for these charges? Who pays each of these ISO and PG&E charges today?

Because it is not known how many customers will contract with Western for CPP or the amount of CPP, Western is not able to estimate the IS/PG&E facilities costs that will be included in the PACI ARR at this time. The ISO/PG&E facilities costs are for delivery of Federal power over the ISO/PG&E transmission system. To the extent costs for delivery of Federal power over the ISO/PG&E transmission system exceeds the current rates charged to Western by PG&E, such costs are paid by PG&E.

127. An agency strongly supports Western's proposal to recover costs (charged by ISO/PG&E that exceed the embedded costs) from PACI sales as a way of honoring the principles of fairness underlying the original agreements. Pragmatically, Western may need to address how to handle a possible cost recovery shortfall if PACI revenues are insufficient to cover the extra costs. For that case, this agency suggests that the amount of relief provided to Western's ISO/PG&E charged customers be equal to the excess revenue collected from PACI sales.

Any possible under collection of the PACI transmission ARR will be addressed in the Western's formal rate process.

128. Western should clarify further how the customer is responsible for providing evidence of its ISO/PG&E costs exceeding Western embedded costs. Western should clarify the cash flow mechanics of whether the Customer pays the ISO/PG&E bill and submits a request for reimbursement of amount exceeding Western's embedded costs or follows a different process.

The details for this process are not available at this time. Western will address this issue as part of the formal rate process.

129. Beyond the point that the proposal is not just and reasonable, many objectionable issues come to mind as one considers implementation of the PACI rate proposal. Please respond to the following:

a. How will Western handle the variation in ISO/PG&E charges for Western power deliveries? The charges will vary substantially based on water year and BR capacity and energy.

Western anticipates including the ISO/PG&E charges on a month by month basis. To the extent they vary month to month, the PACI rate will vary also.

b. Does this include ISO neutrality charges?
No.

c. If the ISO proceeds with locational marginal pricing will Western roll in congestion costs?

No.

d. Will non-direct connects be required to request and use CRRs to hedge ISO congestion costs?

No.

e. Does Western plan to include transmission losses in the reimbursement?

Treatment of losses will be addressed in Western's formal rate process.

f. Western has stated that they believe they cannot charge non-direct connect customers more for transmission than they would charge if Western had built their own facilities (instead of contracting with PG&E for deliveries). Has Western done any study on what that cost would be?

Western's position is that Congress in authorizing the construction of the PACI, executing long term contracts with California Pool Companies and integrating the CVP with PG&E's system, Congress expected that the cost of federal preference power to Western's customers in California, including those served on PG&E's system, would be based on the cost of a federal construction. For purposes of determining the transmission service costs on PG&E's system under 2948A, Western has used PG&E's embedded cost as a proxy for what Western's costs would be if Western had constructed the facilities.

130. What will Western do with the planned PACI ARR if it is not recovered through sales of PACI service? Could the PACI revenue requirements, including the ISO costs for non-direct connected Western power deliveries, be included in Western's power or transmission rates? The anticipated consequence of this rate proposal unjustifiably subsidizes the costs of Western customers who must rely on the ISO Controlled Grid to receive Western power.

Possible under recovery of the PACI revenue requirement will be addressed as part of the formal rate process. The Federal legislation authorizing the PACI intended that Western customers pay costs that would not exceed the cost of Federal construction. To ensure that all Western's customers receive the benefit intended by the Federal legislation authorizing the PACI, certain Western power delivery costs will be included in the PACI transmission ARR.

PM SERVICE

131. If a FLS customer acquires and pays for its own CPP and authorizes Western to schedule the power, will the customer be required to take Portfolio Management services from Western? Will all customers taking PM services pay the same rate per schedule?

A FLS customer must take PM Service. However, PM Service does not provide for the scheduling of power. CPP is Federal power and has to be acquired by Western. A customer with existing third party power contracts can obtain PM service from Western and be a FLS customer. The rate for PM service is the same for all customers.

132. Will Western offer PM service to non-FLS customers?

Western will offer PM service to FLS customers and BR customers who are not VR customers.

133. Would Western consider performing economic dispatch of customer owned units or contracts as part of PM service?

Yes.

PROJECT USE LOADS COSTS

134. Will a CAMS rate be charged? If so, why -- and what services would this entail? Will project use load in the CAISO Control Area be required to pay both CAMS rate and CAISO overheads? Will project use load be paying costs for both a Federal Control Area and CAISO? If so, why?

A CAMS rate will be charged to entities that join the Federal Control Area, except for project use loads. CAMS recovers the cost of meeting WECC control area requirements. This includes monitoring interchange schedules and conducting hourly check outs with adjacent control areas. The rates developed by Western will not apply to project use loads. The cost sub-allocation will determine the costs to be paid by project use loads

135. Please confirm that Western will be funding SC services for Reclamation and pass those costs to Reclamation at the end of the fiscal year. Related to the exit fee application to non-CVP generation, Reclamation views this as a purchase power expense and/or transmission/distribution related expense, therefore, should be funded directly or indirectly by Western. How will Western obtain funding to pay these costs prior to the billing from Western to the Reclamation at the end of each year?

Options available to Western for funding ISO related SC costs and/or exit fees, include use of receipts, Federal reimbursable authority, or other Federally approved funding mechanisms. Western is working with Reclamation to address this issue. Western will need cash from either Reclamation or the CVP water customers to pay the ISO costs. For an update on PG&E's position on exit fees, please see question 1.d.2.

136. Keeping in mind that Reclamation will be handling a substantial amount of the workload for project use loads, will project use loads be treated as a FLS or VR customer?

FLS or VR Customer categories apply only to preference customers.

137. The project use loads scheduling is expected to be aggregated to a much lower level than on a load-point by load-point basis. Does Western concur that the SC and scheduling agent costs will be consolidated into 5 Zones? If not, why?

The ISO costs associated with SC service will be determined by the ISO tariff. Scheduling agent is not a service offered by Western after 12/31/04. The rates developed by Western will not apply to project use loads. The cost sub-allocation will determine the costs to be paid by project use loads

138. Please identify the rates that Western anticipates recovering from CVP Water Users, and the service provided and cost incurred by Western that is recovered in each rate.

Western's rates do not apply to CVP Water Users. The CVP Water Users will pay the costs that result from the cost sub-allocation.

139. Western is responsible for providing transmission/distribution to project use loads. What actions has Western taken to provide transmission/distribution to these loads after contract 2948A expires? How does Western propose to fund the project use transmission/distribution costs? They will occur before such costs are transferred to Reclamation for recovery in its water rates. How will Western fund any of these anticipated CAMS/CAISO charges before such costs are transferred to Reclamation and passed on the water contractors through the water rates?

Western's CAMS service rate will not apply to project use loads. The project use loads will pay the costs that result from the cost sub-allocation. Western is continuing discussions with PG&E on delivery of Federal power to preference customers and project use loads. Western is working with Reclamation to resolve the funding issues.

140. Please provide a summary of all rates that Western anticipates will be charged to a project use loads under the following scenarios:

a) Is directly connected to the federal transmission system at 230kv

b) Is connected to PG&E's distribution system at 60kv

c) Is connected to PG&E's distribution system at 12kv

The rates developed by Western will not apply to CVP Water Users. Costs to be paid by the CVP water customers (project use) will be determined through the cost sub-allocation.

141. How will project use loads be charged for SC, PM, regulation and frequency response, and energy imbalance? If not, why not? It needs to be very clear what rates Western is proposing to recover from the project use loads. Obviously there are rates that apply only to preference power customers and not project use loads, but it is not easily delineated.

The costs to be paid by project use loads are determined through the cost sub-allocation. Western's rates do not apply to project use loads.

142. Western correctly anticipate that all ancillary services associated with project use demands would be self-provided?

Costs for services for project use loads are determined in the cost sub-allocation.

143. We are trying to view this concept with some consistency. Reclamation is the project use customer of the CVP and intends to provide the aggregated project use load schedule to Western. Therefore, we assume Western will view this as one schedule although there would be multiple meter points. (It is recognized there may need to be two schedules if the ISO grid project use loads are a separate schedule). This does not appear to be different than the City of Roseville or SMUD; that is one customer but with multiple meter points. Please clarify if this meets your expectations.

The costs to be paid by Reclamation as the project use customer are determined through the cost sub-allocation. Western's rates do not apply to project use loads.
207. FERC Accepted or Approved Credits or Charges. Please provide your assessment as to whether the statements regarding FERC Accepted or Approved Credits or Charges affects project use generation and project use loads.

Project use loads will pay the costs resulting from the cost sub-allocation. Western's rates do not apply to project use loads.

144. Does Western anticipate charging this CAMS rate to the non-direct connected project use loads existing in ISO control area that are already paying a ISO GMC so, in effect, result in double charges for project use energy loads?

No.

145. What rates does Western anticipate will be charged to project use loads that are not directly connected to the Federal transmission system? Please provide summary examples of anticipated rates to be imposed on project use loads; one with project use load direct connected to the CVP transmission system and the other example of project use loads.

Project use loads will pay the costs resulting from the cost sub-allocation. Western's rates do not apply to project use loads.

SC SERVICE

146. Western states that costs from ISO invoices (even if several customers are grouped under one SC ID) are passed through as if each customer was under a separate ID. To the extent that a preference customer intends to take SC service from Western, how does Western intend to disaggregate SC costs to its customers in a manner that avoids one customer from subsidizing other customers?

Western's settlements system will be programmed to disaggregate costs from ISO invoices to each SC customer as if each customer were under a separate SC ID.

147. Will an agency be charged SC Service fees if they are their own SC or have a SC other than Western?

If a customer does not sign an SC service contract with Western, it will not be billed by Western for SC service.

148. How many Western SC charges can a customer expect each month, given that Western will meet all of the customer's power needs and that there are currently nine delivery points? Is it the sum of one load and one resource times the charge, or nine times that amount? Similar to SC charges, would PM charges be for one load and resource or one each for each nine delivery points?

Each month a SC customer will be charged an amount per schedule for each final daily schedule submitted to the ISO for the service month being billed. This will apply to final daily load and resource schedules submitted to the ISO. The number of schedules per customer will vary based on the number of schedules required for that customer load. For PM service, the customer will be charged for each final daily schedule created to balance the load and resource. The number of schedules per customer will vary based on the number of schedules required for that customer load.

149. We've seen no definitive information on what the order of magnitude might be with regard to the ISO pass-through costs contemplated as part of the SC service. Depending on the magnitude of the ISO pass-through, we would prefer to set up some kind of trust fund with Western that we fund in advance and replenish with one bill a month from Western. We understand that the ISO sends out bills five times a month. We are simply not set up to cut checks five times a month and it would be very inefficient for us to do so.

Western will consider managing a trust fund for customers who wish Western to pay the ISO bills on their behalf. Western will review this option to determine what process is needed to provide this service.

150. For SC service, how do you calculate costs based on the number of customers and not by the number of schedules?

The SC service rate is a $ per schedule rate and will be calculated using the estimated total number of final daily schedules for all SC customers for the year. For example: 20 customers with 6 final daily schedules for 365 days totals 43,800 final daily schedules. This total divided into an estimated ARR of $600,000 results in an estimated rate per schedule of $14 to be applied to each final daily schedule.

151. Please reconcile the SC Service ARR of $600,000 with the amount shown on the cost sub-allocation summary amount provided from/to your staff. Reclamation encourages Western to have appropriate reserves to cover shortfalls in advance funding since 3 months funding ($150,000) seems like a low number for SC service.

The ARR of $600,000 does not reconcile to the amount shown on the cost sub-allocation summary amount provided by Reclamation. The ARR of $600,000 was generated by Western as a preliminary estimate and subject to change. The amount referenced in the cost sub-allocation summary is also estimated to be used for illustrative purposes only. The $600,000 ARR refers to the per schedule charge to cover Western's costs associated with serving as a SC. The trust fund for SC costs is for ISO related costs, not necessarily for Western's SC costs.

GENERAL COMMENTS

152. An entity is very supportive of Western's unbundling of services to collect the separate costs for each, and to segregate the risks to the subscribers.

153. A customer fully supports the fair allocation of costs, which balances the goals of pursuing original project objectives and reflection of cost causation.

154. A customer was also very supportive of Western's proposal to continue to use joint assets like the PACI to provide joint benefits to all customers by providing some shielding to the subset of customers exposed to ISO/PG&E charges.

155. A customer supports Western's designation of CPP purchases to be federal power purchases.

156. With regard to transmission, we hope that we understood Western's intent and that Western follows through. What we understood was that Western will include whatever PG&E and the ISO decides to charge to deliver Western's power to Western customers that is above the "embedded cost", in the charge calculation for use of the PACI. Those revenues will net out the PG&E or ISO add-ons so that the cost of transmission to Western customers will remain at the "embedded cost". To implement their strategy, PG&E's lobbying included a commitment to provide both support for the hydroelectric generation and the remaining transmission needs, both at cost based rates.

157. FP customers must pay their fair share costs of the project use costs.

158. Western must be careful that they do not cause problems by allocating too much costs to summer. There are restoration costs that need to be included in the determination by month.

159. Western indicates approximately 77 MW of COTP capacity is available for sale. Please include placeholders for future project use plans with any commitments when selling this capacity under the assumption that the CVP transmission system supports project needs before marketing of surplus can be accomplished.

160. As mentioned previously, Western has funded 3rd party transmission service to meet Reclamation project use load needs since Western's existence. Western retains the responsibility to provide transmission/distribution to project use loads. We request Western to continue to take appropriate actions to assure the transmission/distribution is available when needed for current and future project use loads and when it has been determined by Reclamation to be the most economical means to provide electrical service to that project use load.

161. The information presented at the Informal Rates meeting states that, under PG&E's current position, the cost of delivering CVP power to Customers connected to the PG&E

grid is likely to increase substantially in the post-2004 period. We agree with this observation. Indeed, in our analysis, the confidential information provided by PG&E grossly underestimates the actual increases in delivery costs that a customer on PG&E's system would pay under PG&E's position. According to the Informal Rates meeting, such large cost increases could be mitigated by including certain Western power delivery costs in the ARR for PACI for ratemaking purposes. We strongly support Western's commitment to minimize the costs of delivering Western power to customers on the PG&E system. In our view, including a portion of Western's delivery costs in the ARR of the PACI and/or other extra-high voltage (EHV) transmission facilities is an entirely appropriate tool for achieving this objective. Absent such mechanisms, customers on PG&E's system will be seriously harmed through no fault of their own. Western's PACI has been an integral component of the CVP power system since the 1960s. This proposal by Western is therefore an appropriate cost sharing methodology. We certainly believe that such an approach is within the Administrator's ratemaking authority and would help to avoid disproportionate rate increases for Western's remote customers on PG&E's system.

162. We strongly support the rate design for the PACI transmission service that includes the "greater than embedded cost" portion of ISO/PG&E facility charges.

163. Western should actively (legally) oppose PG&E's attempts to impose exit fees on non-hydro power delivered to either project use loads or preference loads.

164. Western should oppose PG&E's attempts to prevent additional project loads from receiving Western power.

165. We expect that, as a result of renegotiation of the Coordinated Operations Agreement, that Western would become the party responsible for providing transaction information for the users of the COTP to the involved control area operators. We expect to be discussing this issue with Western separately, but in this forum suggest only that Western anticipate recovering the costs of this activity.

166. As a direct connect customer, that has paid a high price over time to insure that Western power can be delivered without "other" charges, we cannot see how Western can subsidize its power deliveries to other Western customers that have chosen NOT to develop an interconnection with Western. If Western's approach is to use sales of the PACI transmission as a revenue source to offset the ISO and PG&E costs, we are opposed to such a concept. Our opposition is based on the fundamentals of cost causation. Those entities that cause the ISO/PG&E costs for delivery over the ISO/PG&E systems should bear the responsibility for payment of such costs consistent with the final marketing plan as published in the Federal Register. Over the last 15 years, no other customers have ever offered to help pay the costs associated with our building of direct interconnections. Western should not assume the payment role for any transmission/facility costs that are not directly related to delivery of CVP power over the CVP system.

167. Direct-connected customers incurred their own capital costs for their Western interconnections, and do not require ISO/PG&E facilities for delivery of their BR power; therefore, under long-standing cost causation principles they should not have to pay for those embedded costs that do not benefit them.

168. As a FP customer, we believe that Western has a statutory obligation to provide not only electrical power, but also the delivery of that power as provided by the 1962 Flood Control Act.

169. As a FP customer it is our understanding that our CVP oiwer will include CVP Transmission Service, SSC&D Service, Reactive Power and Voltage Control, and Operating Reserves. Additionally, we expect to be a FLS customer that will also take PM service, and because we are located within the ISO control area, SC Services.

170. Our concern is with the proposed funding terms of the CPP. We understand that the terms will require either appropriations, advance funding by the customer requesting CPP, Use of Receipts authority or other federally approved funding mechanisms. Western has noted that if advance funding is used, advancement of funds for the entire purchase is required. Such an arrangement would be an exception to standard business practices for payment of services and therefore, would present a substantial problem to us. Depending on the level of load served under the program and the term of the power supply contract, we could be required to make an advance payment approaching $100 million. This is well beyond our capacity to self-finance. Possible alternatives would be to obtain outside financing, which would result in considerable additional expense, or to have Western enter into short-term contracts, which would add considerable volatility in pricing. We understand that most other Western customers are likely to have similar problems with full advancement of funds under the CPP. We believe that other funding arrangements identified in the draft plan -- such as the Use of Receipts authority would avoid the serious problems noted above to us and other customers without imposing additional costs or financial risks on Western. We request that Western fully examine these alternatives before finalizing the marketing plan.

171**.** PG&E's position appears to be to attempt to charge exit fees to end use customers. Exit fees are the fees calculated to make PG&E financially whole with respect to its net revenue from the customer pre and post new supplier (other than CVP hydro). When applied to project use loads this results in PG&E <u>owing</u> Western considerable exit fees to make PG&E whole to the losses that they say they incur on that load currently.

172. We strongly support Western's proposal to recover costs (charged by ISO/PG&E that exceed the embedded costs) from PACI sales as a way of honoring the principles of fairness underlying the original agreements. Western correctly proposes to make other costs such as GMC and exit fees, the responsibility of the customer.

173. FP customers should never have excess energy to be placed into the exchange. They should be handled just like project use in that they get their energy scheduled first.

174. As discussed at the May 14 meeting, Western may be able to shift costs such that the preference power MRR more closely approximates monthly CVP power deliveries. We urge Western to pursue all possible opportunities for such rationalization. The ultimate goal of these efforts should be to make the effective per unit cost of BR power approximately constant across the year. There may be other options for achieving this objective.

175. We oppose Western's proposal to include the costs for use of the ISO grid and PG&E transmission and distribution facilities to deliver Western power in the Annual Revenue Requirement (AARR@) for Western's PACI rights. Just and reasonable rate design does not support the rationalization that is offered in your proposal. It is irrelevant if PACI was constructed to ensure that Western would be able to serve its customers at a cost not to exceed the cost of Federal construction. Western's proposal seeks to assign unrelated costs to a distinctly different service. As proposed, Western's PACI service is not integrated in the operation of the ISO Controlled Grid. There is no reciprocal benefit accruing to either PACI service customers or those who are forced to subsidize entities that are otherwise exposed to ISO/PG&E costs. If a Western customer or another entity buys PACI service it does not gain access to the transmission capability on the ISO Controlled Grid for which it is required to pay under this proposal.

176. We support users paying user fees, i.e. other costs associated with ISO or PG&E, such as GMC, exit fee, etc. that would be the responsibility of the customer and would not be included in the PACI transmission ARR.

177. Regarding the PACI revenue requirement, the PG&E tariff is still very high although the 50 year old PG&E lines that have provided service are probably completely depreciated on PG&E's financial balance sheets. Because of this all costs in excess of the embedded cost of transmission/distribution should be added to the PACI revenue requirement. Otherwise, project use loads are being charged more than the necessary amount to ensure cost recovery, and this would entail realization of a profit.

178. A customer is interested in securing a BR percentage of ancillary service benefits regardless of the extent of the federal control area. Rate setting methods should be explored to accomplish this for customers regardless of how long it may take for the federal control area to reach them.

179. During the informal rate meeting, we thought we heard that Western intends to send us a bill for ISO charges and have us pay the ISO directly. For several reasons, we would prefer to pay Western, even if we don't establish a trust fund.

180. I understand why you are not proposing a shifting of ARR for FP, and it is not that big a deal since the load is fairly stable month to month, but it would be helpful if our monthly payments to Western were patterned similar to the present case.